LBNL-61313

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A Regional Approach to Market Monitoring in the West

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October 2006

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability, Permitting, Siting and Analysis of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231 and Western Interstate Energy Board contract #2006-Elec-1.

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A Regional Approach to Market Monitoring in the West

Prepared for
Western Interstate Energy Board
Committee on Regional Electric Power Cooperation

and
Office of Electricity Delivery and Energy Reliability
Department of Energy

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Acronyms and Abbreviations

APS	Arizona Public Service
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CFTC	Commodity Futures Trading Commission
CEMS	Continuous Emissions Monitoring System
EQR	Electric Quarterly Report
FC	Four Corners
FERC	Federal Energy Regulatory Commission
ICE	Intercontinental Exchange
IE	Independent Evaluator
LMP	Locational Marginal Price
MBR	Market-Based Rate
MM	Market Monitor
NERC	North American Reliability Council
PE	Potomac Economics
PG&E	Pacific Gas and Electric Company
PNM	Public Service of New Mexico
PV	Palo Verde
RFO	Request for Offers
RTO	Regional Transmission Organizations
SMUD	Sacramento Municipal Utility District
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SSG-WI	Seams Steering Group of the Western Interconnection
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

The West experienced very high wholesale power prices in 2000-2001 and debate continues about the extent to which these prices were the result of market fundamentals as opposed to market manipulation. Although the Federal Energy Regulatory Commission (FERC) eventually investigated claims of market manipulation in Western wholesale electricity markets, the situation prompted state regulators and policymakers that participate in the Western Interstate Energy Board Committee on Regional Electric Power Cooperation as well as some industry market participants to seek to develop some independent capability to monitor wholesale markets in the West.

In the electric industry, market monitoring involves the systematic analysis of prices and behavior in power markets to determine when and whether potentially anti-competitive behavior is occurring. Historically, federal and state regulators have overseen utilities' rates and costs to provide electricity service to ensure that consumers were protected from abuse from monopoly companies. As market forces have been introduced into parts of the power industry over the past two decades, part of consumers' bills reflect prices set in markets, rather than cost-based rates. Regulators have begun to look at mechanisms, such as market monitoring activities, as one way to help assure that prices set in markets are not adversely impacted by market manipulation.

For a number of reasons, Western wholesale power markets are somewhat more opaque than those in some other parts of the country. For example, a substantial amount of electricity trade in the West occurs through bilateral markets, with a limited amount of information about transactions reported on electronic trading platforms. Also, many utilities in the West are essentially vertically integrated, tending to meet their incremental needs through investment and bilateral contracts rather than the shorter-term transactions that are typically the focus of market monitoring. The Western Interconnection outside of California and Alberta also does not have Regional Transmission Organizations (RTO) that administer short-term markets and transactions, collect and publish voluminous market data, and maintain formal market monitoring functions.

In light of the special characteristics of Western markets, what kinds of market monitoring functions can be developed that work well for the West? This study examines the feasibility of West-wide market monitoring given readily available data. We explore two main analytic techniques for market monitoring: the econometric analysis of wholesale power prices and a particular type of production cost modeling. Of the two, we conclude that the econometric approach is likely to be more feasible and could be a useful addition to West-wide market monitoring efforts. Our focus on analytic techniques is intended to support discussions in the West on how the Western power market can be effectively monitored on a routine basis using a variety of analytic tools, information screens, and other market-monitoring resources. These larger and important institutional implications, including the relationship between FERC activities and those that would be sponsored in the West, were not part of the scope of our study.

<u>Analytic tools and approaches</u>

There are a number of analytic techniques that can be used to assess competitive conditions in wholesale power markets. These techniques vary in terms of their analytic sophistication, ease of use, and data intensity. Essentially, each method attempts to establish a benchmark for wholesale prices in a well-functioning competitive market. Our study reviews a wider set of techniques, and focuses on two specific techniques, econometric analysis and production cost modeling. We also describe issues that affect the process and institutional setting for market monitoring in the West outside of California and Alberta. In particular, we examine the roles of a few existing "company-specific market monitors." We observe that they tend to focus on monitoring the potential for affiliate abuse within vertically integrated utility company (e.g., a utility discriminates in favor of its own generation affiliate during a resource procurement or in the provision of transmission service). We conclude that there is little overlap between the roles of such company-specific market monitors and the likely role(s) of a prospective West-wide market monitor.

Econometric modeling of wholesale power prices

Econometrics uses well-established statistical methods that can be used to model the "normal" relationship between wholesale power prices and a set of fundamental drivers of wholesale prices. Econometric models are transparent and flexible in the sense that they can be adapted to whatever data happen to be available. As part of a market monitoring function, econometric tools may help identify "normal" prices as one way to identify situations when abnormal price arise, which may deserve further investigation.

To explore the feasibility of this approach, we developed several econometric models of day-ahead on-peak power prices at two major trading hubs in the West – Palo Verde and Mid-Columbia – as functions of the price of natural gas, a major input to the generation of electricity. Our models also reflect other variables that influence the supply and demand for electricity including: the level of end-user demand at various locations in the West, the availability of nuclear generating units, variables that capture the availability of hydroelectricity in the Pacific Northwest, and a series of variables designed to capture the regular seasonal variation in wholesale power prices. For Palo Verde, we find that our relatively simple models produce results (i.e., parameter estimates) that are economically plausible and explain a significant fraction of the variation in power prices. For example, our most complete model of Palo Verde prices explains over 90 percent of the variation in price (expressed as (log) price).

Our models establish a benchmark that can be used to identify outlier prices that are potentially the result of anti-competitive behavior and may warrant further investigation. Figure ES-1 shows the prices at Palo Verde predicted by one of our models, along with a standard range of prices above and below our price estimates (i.e., a three standard-error band around the predictions of the model). The blue dots are outliers that fall outside of these bands. The three standard-error criterion for identifying outliers is quite forgiving, so we identify relatively few outliers. On investigating these outliers, we were able to link them to well-defined events – such as the outages of major coal units – that are not captured by variables in our model.

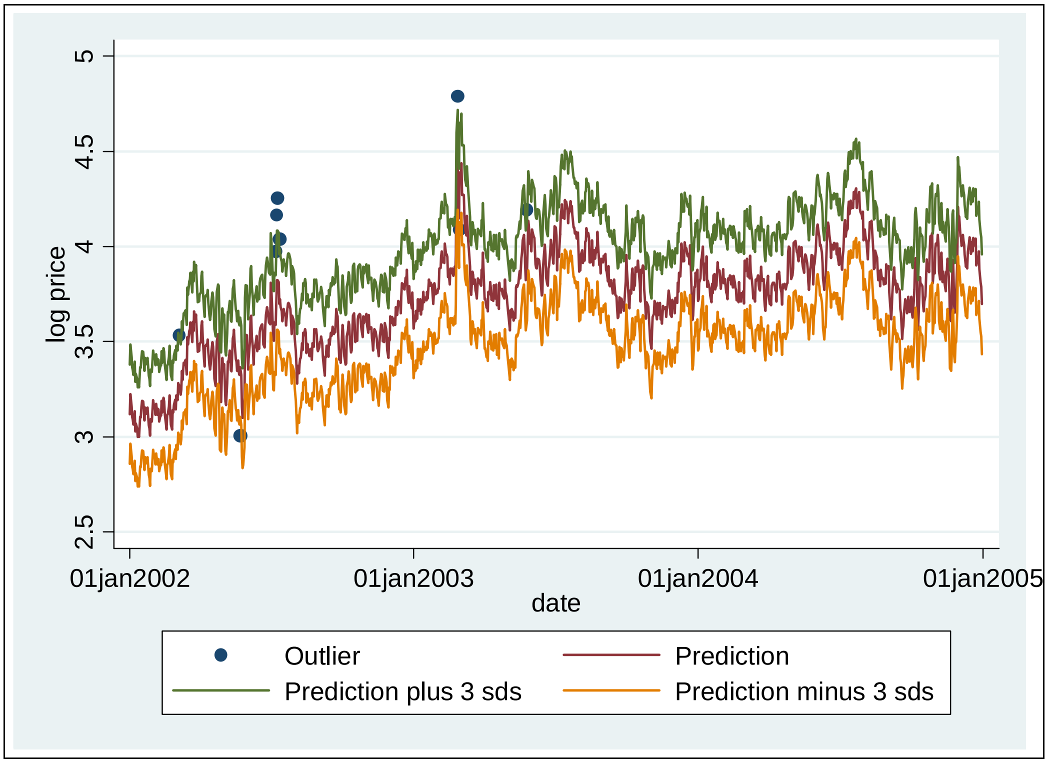

Figure ES-1. Palo Verde predicted prices, 3-standard error bands, and outliers

Our econometric models of Mid-Columbia prices raised a number of technical challenges. Several of the parameter estimates produced by our models are not economically plausible or do not have the expected sign, suggesting problems in model specification. In particular, the models do not capture adequately the effect of the spring runoff on wholesale prices. This suggests that if econometric models were actually used for market monitoring, more attention to the unique dynamics of hydroelectricity in the Pacific Northwest would be required.

Econometric analyses must be implemented and interpreted with care. For example, the specification of the exact functional form of an econometric equation can be guided by good econometric practice and economic theory, but is ultimately more art than science. In addition, the benchmark prices that are predicted by the models are only as "normal" as the data from which the models are estimated. If the models are estimated on data from a period in which prices were consistently supra-competitive, then the benchmark prices will also be above competitive levels. Further, there are subtle issues related to the specification of the geographic markets being analyzed when the geographic scope of electricity markets can change due to transmission congestion. Despite these problems, we view the econometric approach as a feasible and potentially fruitful approach to market monitoring in the West.

Production cost modeling

We also explored the use of production cost models for market monitoring in the West. Production cost models are detailed simulations of the operation of power systems, including operating constraints on generating units and transmission constraints. Their complexity is both a blessing and a curse for market monitoring. On the one hand, they capture in great detail the types of real-world physical constraints that other types of analyses may only be able to capture more crudely. Also, these results have been used in utility and regulatory contexts for decades and are familiar tools. On the other hand, they are somewhat “black box” in nature, require extremely detailed data and are time- and resource-intensive to run and maintain.

We discuss two modes of using production cost models for market monitoring. First, we examine the possibility of updating model inputs and running models on a daily or similar basis so that the simulations reflect current system conditions. We conclude that this approach is likely to be extremely costly at best and infeasible at worst. Second, we consider the usefulness of production cost simulations based on a few discrete scenarios for understanding observed prices. The idea is that if the simulations cover a sufficiently long time period and/or sufficiently diverse conditions, they will contain valid proxies for observed conditions at any given point in time.

We test this idea using variations on a set of simulations that were developed originally by the Seams Steering Group – Western Interconnection (SSG-WI) to support long-run, electric system planning efforts. We conclude that these specific simulations produce prices and price-patterns that bear little resemblance to observed prices and hence are of limited usefulness for assessing current market conditions. The relationship between the prices produced by the simulations and observed prices for one location is shown in Figure ES-2. This figure displays simulated market heat-rates (i.e., ratios of the power price to the gas price), by month for Arizona for a range of gas prices, and observed market heat-rates for three recent years for Palo Verde, a trading hub in Arizona. The simulated market heat rates are generally significantly below the observed market heat rates and lack any of the regular seasonal patterns that are present in the observed market heat rates.

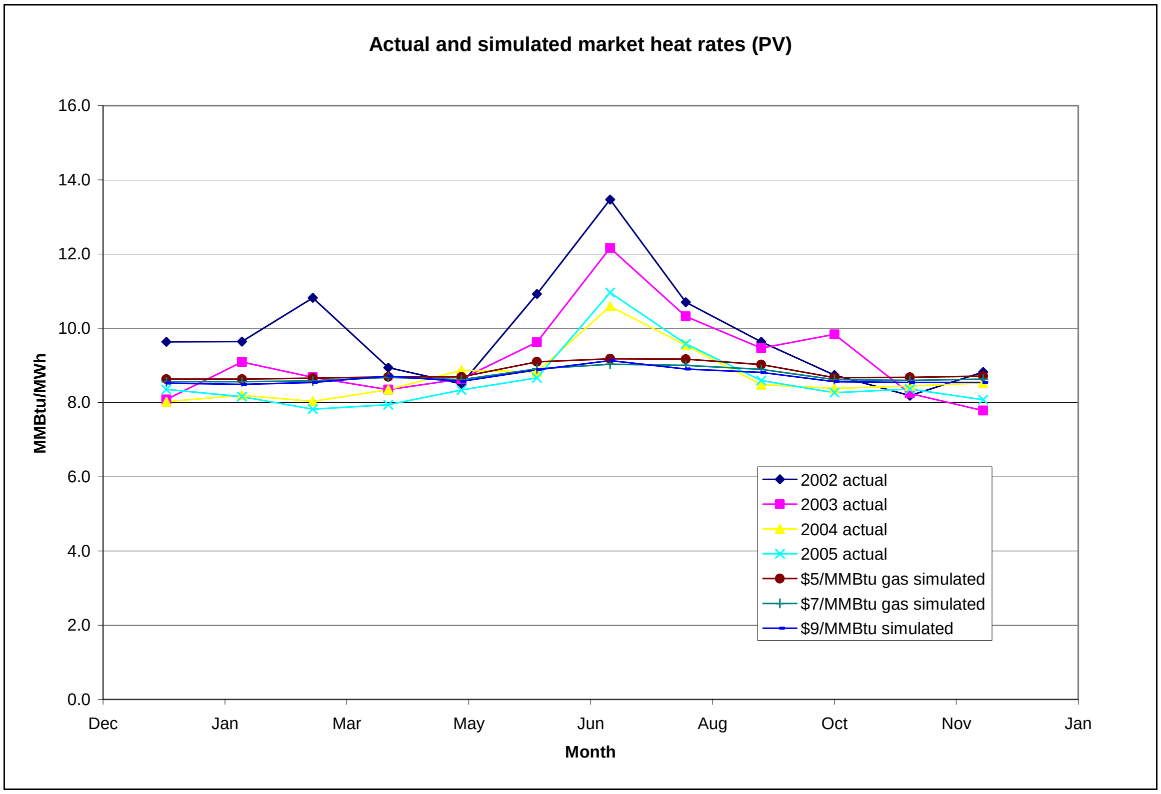

Figure ES-2. Observed and simulated on-peak market heat-rates (PV)

A comparison of actual and simulated market heat-rates for Mid-Columbia shows even wider discrepancies between the level and pattern of simulated and actual market heat-rates. In particular, the simulations do not seem to capture the dramatic dip in power prices that occurs during the spring runoff in the Pacific Northwest.

We fully acknowledge that the simulations were originally developed to model a future year (2008) and contain resources and transmission additions that do not currently exist. Hence, it is not surprising that they produce prices that are unrealistic by current standards. It is an open question whether a parsimonious set of production cost model simulations that accurately reflect current supply and demand fundamentals could be useful for market monitoring. Based on what we do know and observe about the "black box" nature of production cost models in general, and the difficulty inherent in reconciling the extent of optimization in production cost models with real-world operating practices, we believe the answer is "no."

1. Introduction

This report explores some approaches to wholesale power market monitoring in the Western Interconnection outside of California and Alberta. By market monitoring, we mean the systematic analysis of market behavior and outcomes to identify behavior that is inconsistent with well-functioning competitive markets. Such behavior may include the exercise of market power, e.g., withholding supply from the market in order to raise price.[1]

In the U.S., Regional Transmission Organizations (RTOs) with "Day 2" functions[2] generally have dedicated market monitoring functions. The market monitors may be RTO staff members, independent consultants, or both. The Federal Energy Regulatory Commission (FERC) treats applications to sell at market-based rates from suppliers in markets with the full complement of "Day 2" functions, including formal market monitoring, more leniently than other applications.[3]

While we fully acknowledge the wide range of views on the costs and benefits of RTOs, it is simply a fact that market monitoring in RTOs is easier—primarily because of the voluminous amounts of data produced in the centralized "Day 2" markets administered by RTOs. RTO market monitors typically have access to data on the hourly operations of individual units, their bids into various centrally administered, bid-based markets —including markets for both energy and ancillary services, estimates of units' variable costs, hourly prices at multiple locations and for multiple products, detailed information on transmission constraints, and other data not typically available in non-Day 2 RTOs and other bilateral markets, such as exist in the Western United States.

Because of the absence of publicly and/or centrally collected data for the Western U.S. wholesale power markets outside of California, it is generally infeasible to replicate the analyses performed by market monitors in Day 2 RTOs.[4] Therefore, it is necessary to approach market monitoring in a different way than has been done in organized markets.

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[1] In many markets, in addition to monitoring current market outcomes and behavior, Market Monitors also play a constructive role in designing more efficient market rules and institutions. This second role is not the focus of this report.

[2] In the industry parlance of RTOs with different sets of functions, a so-called "Day One" RTO includes the following types of grid operator functions: open-access transmission service, congestion management, ancillary services and interregional planning. By contrast, a so-called "Day Two" RTO would involve all the functions of a Day One RTO as well as operation of a bid-based, security-constrained market with economic dispatch, locational pricing, and financial transmission rights or capacity markets. http://www.ferc.gov/press-room/press-releases/2004/2004-4/10-06-04.asp .

[3] For example, a current FERC Notice of Proposed Rulemaking (http://www.ferc.gov/whats-new/comm-meet/051806/E-2.pdf), which reflects recent *de facto* FERC policy, suggests that sellers located in RTO markets with established market monitoring protocols may limit their analysis to the geographic market defined by the footprint of the relevant RTO in their market-based rate filings. (¶ 25) In contrast, suppliers outside of RTOs are frequently required to examine multiple geographic markets. Similarly, the market-based rate filings of suppliers in RTO markets can reflect explicitly the market power mitigation measures to which the suppliers are subject. (¶ 60).

[4] For examples of the analyses performed by the CAISO market monitor, see http://www.caiso.com/docs/2005/01/13/2005011316200513508.html.

Our attempt to do so is the subject of this report. In section 2, we describe the types of wholesale power markets that exist in the West outside of California and Alberta, along with the type of information available about the performance of such markets. In sections 3 and 4, we review some types of analyses that might be used for market monitoring in the absence of RTO-style data and the data that might be used in such analyses. In section 5, we present results of an exploratory analysis that could be conducted by a West-wide market monitor, an econometric analysis of bilateral prices. In section 6, we discuss the results of a detailed production cost simulation of the Western power market. Production cost simulations produce the types of detailed information that are typically available to market monitors in Day 2 RTO markets. Ultimately, we are unable to draw firm conclusions based on the results of the simulations because the conditions modeled in the simulations — which were not originally intended for market monitoring — were quite different from current and recent historical conditions. In section 7, we summarize the activities of market monitors retained by several individual utilities in the Western region. Generally, the roles of these "company-specific" market monitors are very different from the roles of market monitors in RTOs. While market monitors in RTOs review competitive conditions in short-term wholesale markets, assess market rules, and evaluate market structure, company-specific market monitors generally oversee long-term wholesale procurement with an emphasis on limiting affiliate abuse. Finally, we offer some concluding remarks in Section 8.

2. Wholesale power markets in the West outside of California

Wholesale markets in the Western Interconnection outside of California and Alberta are different than organized markets with RTOs in at least four main ways. First and foremost, the structure of the market is not an RTO structure, so there is no centralized West-wide unit commitment and dispatch. Consequently, the information that RTOs collect in the process of performing unit commitment and dispatch, such as unit-specific bid information, are simply not available for market monitoring. In addition, non-RTO markets do not produce the highly geographically and temporally disaggregated prices that are the result of a market-based centralized unit-commitment and dispatch. As FERC has noted:

> What information is available to regulators (and when) depends largely on the structure of the market. Locational marginal, day-ahead, and real-time pricing, along with capacity and ancillary services within RTO markets, are almost entirely transparent and make much information available in real time. Such transparency rests on standardized operations and large, centralized mechanisms to collect and disseminate the information. By contrast, most natural gas markets and bilateral electric markets provide far less detailed information, depending instead on trade publications to provide price indices.[5]

Second, in the absence of RTO markets, there is a substantial amount of trade in the West through bilateral markets. This is relatively well understood, and supported with information about the extent of bilateral trading in wholesale power markets. Volumes on the Intercontinental Exchange (ICE), an electronic platform for trading standardized natural gas, power, and other energy-related contracts, offers one measure of such trading activity outside of RTO-mediated markets. For example, ICE volumes for on-peak deliveries to Palo Verde, the most liquid of several hubs in the Southwest, averaged 20,953 MW in 2004, relative to annual load in the entire Southwest (excluding California) of 180,154 GWh.[6] Similarly, ICE volumes for on-peak deliveries to Mid-Columbia, the most liquid hub in the Pacific Northwest, averaged 23,636 MW relative to annual load in the entire Pacific Northwest of 223,148 GWh.[7] In contrast, for New York, an RTO market, ICE volumes for on-peak delivery to the most liquid delivery point (Zone A) averaged only 3,445 MW in 2004 compared to annual net generation of 160,210 GWh — or approximately one-fifth the level of on-peak deliveries of ICE volumes as is exhibited at Palo Verde and Mid-Columbia.[8]

Third, many U.S. utilities in the West outside of California are essentially vertically integrated, obviating to a large degree the need to purchase from wholesale markets to serve load. To the extent that utilities are short or long, they frequently address these imbalances through long-term contracts, rather than through the shorter-term transactions that are typically the focus of market

[5] FERC (2005), p. 36.

[6] *Ibid.*, p. 121.

[7] *Ibid.*, p. 99.

[8] We divide on-peak deliveries of ICE volumes in a particular region by the total annual load in the same region for this comparison.

monitoring. Even when they do trade in short-term markets (as indicated above), it is typically through bilateral contracts, since there are not bid-based, centralized balancing markets such as provided by Day 2 RTOs.

Fourth, non-FERC-jurisdictional entities, such as Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA), play an important role in Western wholesale power markets.[9] They are not subject to the same reporting requirements as FERC-jurisdictional entities — such as reporting wholesale transaction in the Electric Quarterly Reports discussed below. This lends yet another layer of opacity to Western wholesale power markets.

[9] FERC (2005) states that BPA "meets approximately 44% of the region's (i.e., the Pacific Northwest's) firm energy supply from resources under its control." (p. 99)

3. Analytic Techniques

Even in the absence of the detailed data available in Day 2 RTOs, there are a variety of analytic techniques that could be applied to market monitoring in the West outside of California and Alberta. This section provides a brief overview of these techniques.

3.1 Supply Stack

The simplest approach to market monitoring involves constructing a competitive benchmark using a simple generation supply stack. This approach entails stacking the resources available to meet load in a region in economic merit order to form a supply curve. The competitive benchmark price for a given period is then determined at the point on this curve corresponding to the period's load adjusted for certain ancillary service requirements. Divergences between competitive benchmark prices and observed prices may be attributable to the exercise of market power. This approach was applied to the U.K. market by Wolfram (1999). Several authors including Borenstein, Bushnell, and Wolak (2002) and Joskow and Kahn (2002) have applied a similar approach to California.

There are limits to the supply stack approach.[10] First, it tends to ignore some of the geographic characteristics of wholesale power markets. It may be well-suited to markets with relatively simple network configurations, such as California's, but it is poorly suited to analyzing the exercise of market power across broad regions with internal transmission constraints that bind only intermittently. To the extent that transmission constraints are reflected in supply stack analysis, they are represented crudely and in a way that relies on data that may not be readily available outside of RTO markets. For example, the supply stack analyses of California differentiate between resources internal to California and imports. In the case of at least the Borenstein, Bushnell, and Wolak paper (BBW), the representation of imports is based on bids into one of the markets that was administered by the California ISO. These bid data were confidential when the authors wrote their paper. BBW's analysis also relies on other confidential data, such as data on must-run and hydro generation.

In addition, supply stack approaches ignore operating constraints in a way that tends to understate prices during on-peak periods and overstate prices in off-peak periods relative to the prices that would be realized in a perfectly competitive market. Ramping constraints limit the ability of certain generators to reach maximum output during peak periods as quickly as the supply stack models assume. During the night, many generators run at minimum generation levels in order to avoid startup costs and to be available to meet load the following day, whereas supply stack models tend to assume that they are completely off-line.

3.2 Production Cost Models

Using production cost models, such as Prosym and GE-MAPS, to develop competitive benchmark wholesale electricity prices might address many of the problems associated with supply stack models. For example, production cost models can handle transmission and operating constraints, and represent the relationship between loads and resources in great detail.

[10] See Harvey and Hogan (2002) for a more detailed critique of the supply stack approach.

The main downsides associated with production cost models for market monitoring is that they are expensive to obtain, set up and maintain, and probably too complicated to run very often unless a model has been taken in-house by a market monitoring organization with staff trained and dedicated to the function. In particular, if a production cost model is to be used for market monitoring (as opposed to its use for long-term planning purposes, for example), the data that are used in the model must reflect current conditions, not expected or average conditions as are typically reflected in such models. Updating the detailed inputs of a production cost model to reflect current fuel prices, loads, and plant availability presumably would require a multi-person full time staff with access to information about changing conditions in the market on a current basis.

In addition, production-cost models have a tendency to "over optimize," i.e., they tend to simulate unit commitment and dispatch that is more efficient than can be achieved in reality. In part, this is because they assume a greater degree of foresight about market conditions than control area operators and market participants typically have, especially in non-RTO environments. For example, models may assume that generators know with certainty what loads are likely to be several days out. In addition, they tend to assume implicitly a greater degree of coordination between separate control areas, such as exist in the West, than could be or has been realized.[11]

3.3 Econometric Models

Econometric models are a third approach. They can be used to develop statistical relationships between wholesale prices and readily observable factors that influence prices, such as fuel prices and loads. Prices that deviate in a statistically significant manner from the prices predicted by econometric models may merit further investigation and indicate the exercise of market power.

To be useful in a market monitoring context, econometric models must be specified and interpreted with care. For example, in order to identify anomalous prices, it is necessary to make assumptions about what constitute "normal" prices. If the model that establishes the normal relationship between prices and the fundamental drivers of prices is estimated on data from a period in which prices were high, perhaps due to the exercise of market power, then subsequent high prices will look normal according to the model.

The econometric approach has three main virtues. First, it can be tailored to whatever data are readily available. Relatively crude data can be used to estimate relatively simple models while more detailed data can be used to estimate more complicated models. Second, it provides a framework for thinking about the precision of models and the expected frequency of large deviations from established relationships between prices, on the one hand, and supply and demand fundamentals, on the other hand, even in the absence of the exercise of market power. Third, econometric models are used in a variety of contexts. Consequently, there is a deep base of knowledge among practitioners with respect to methodological issues, strengths, weaknesses,

[11] This coordination is one argument that is invoked frequently in favor of geographically broad RTOs (Midwest ISO 2006).

and so forth. As such, they tend to be relatively transparent, with norms about reporting statistics to help guide interpretation of their results.

The FERC staff recently has attempted to develop the types of econometric models that we are discussing here.[12] Some ISO/RTOs that have the data to perform more sophisticated analyses, also use simple econometric models to identify areas for more detailed analysis.[13] Similar models have also been used in regulatory proceedings.[14] In section 5, we develop some simple econometric models of wholesale power prices in the West and believe that this approach has promise for market monitoring in non-RTO markets.

3.4 Game-theoretic Simulations

The preceding three sections discussed methods for developing estimates of competitive benchmark prices. However, they provide little insight into the range of outcomes that might be realized if market participants behave anti-competitively, using strategic behavior to affect prices. In order to get a sense for the range of outcomes in such circumstances, it is necessary to model strategic behavior directly. Models of strategic behavior are based on the same types of data as supply stack and production cost models. They range from the types of comparatively simple, single-area Cournot models developed and promoted by Bushnell and his co-authors,[15] to models that allow for a broader range of strategic behavior[16] or allow for both strategic behavior and transmission constraints.[17] For tractability, these models radically simplify strategic behavior. For example, Cournot models assume that each strategic supplier decides how much to produce in each period conditional on what he expects other suppliers to provide. The models attempt to identify "Nash equilibria" in which each supplier is maximizing profits conditional on his expectations about the behavior of other suppliers and each supplier's expectations about other suppliers' behavior are in fact consistent with observed behavior. Other models assume that suppliers will bid linear or other "supply curves" that express their willingness to supply different quantities at different prices. Models that incorporate the potential for transmission congestion can become unwieldy. One common assumption in the literature is to assume that suppliers do not fully internalize the effect of their own behavior on transmission congestion. Few if any models of strategic behavior address transmission and other operating constraints at the level of engineering detail of production cost models. These models can be difficult to solve and are sensitive to assumptions. As the authors of one paper note, "…it has been well known

[12] See Yoo and Meroney (2005).

[13] See chapter 5 of ISO-New England (2003) as an example.

[14] In the New Jersey proceeding reviewing the Exelon/PSEG merger, both Petitioners and Intervenors used econometric models to quantify the benefits in terms of lower wholesale prices due to the increased availability of nuclear units that may result from the merger (Schnitzer 2005).

[15] For example, see Bushnell, Mansur, and Saravia (2004), Bushnell (2003), and Borenstein and Bushnell (1999). Cournot models are based on quantity competition. This is especially relevant to electricity markets where capacity constraints limit quantities both in the long run and in the short run through unit commitment.

[16] See Baldick, Grant, and Kahn (2004). These models reflect the actual form of electricity market bidding, where suppliers offer price and quantity schedules, but are more difficult to solve than Cournot models.

[17] Neuhoff, et al. (2005).

that structural and behavioral assumptions in oligopoly models affect the results. We have shown that even within a family of models (Cournot), assumptions concerning transmission can dramatically affect the solutions of electricity market models."[18]

3.5 Analyses of Physical Withholding

Another approach involves examining market behavior directly at the supplier, plant, or unit levels. Many forms of anticompetitive behavior effectively involve withdrawing capacity from the market. Using data on the operation of units, it is possible to infer whether units that plausibly could have operated profitably did not.[19] Any such analysis must carefully account for all of the operating costs of a unit and legitimate forced and maintenance outages. Determining whether outages are legitimate requires special effort. During the 2000-2001 Western electricity crisis there were several investigations of such issues. These investigations reveal how much complexity and judgment can be required in these cases.[20]

Outside of RTOs, the main source of data on generating unit-level operations is EPA's Continuous Emissions Monitoring System (CEMS) data. These data are only available for large steam units and with a significant time lag (e.g., one year or longer after an event occurs). Because of the time lag in their release, any analysis of the CEMS data are not well-suited to near real-time market monitoring, but may provide useful detail about the market months or year after the fact.

[18] Ibid.

[19] Joskow and Kahn (2002) include an example of such an analysis.

[20] See FERC (2001a). The background facts on this matter were not released by FERC at the time of this settlement. Subsequently this information became available as the result of a Freedom of Information Act request; see "Non-Public Appendix to Order Directing Williams Energy Marketing & Trading Company and AES Southland, Inc, to Show Cause," Docket No. IN01-03-001, available at http://news.corporate.findlaw.com/hdocs/docs/ferc/ williamsaes111502osc.pdf . Other investigations include CPUC (2002), and FERC (2001b).

4. Data

In this section, we describe the types of information and data that could be used for market monitoring in the West.

4.1 Bilateral Price Data

The commercial price-reporting services such as Platts, Bloomberg, and Dow Jones report price indices based on averages of bilateral transaction prices reported for major trading hubs in the West. The most widely quoted prices are for standard day-ahead products, such as sixteen hour on-peak strips, but prices for hourly products are becoming increasingly available.[21] The quoted prices are available on a near real-time basis. Because index prices are based on the voluntary reporting of transaction prices, they lack the transparency and verifiability of clearing prices determined in Day 2 RTO markets. Even so, such bilateral prices have become increasingly reliable due to reforms implemented in reaction to alleged attempts to manipulate index prices through reporting false transactions that occurred during the 2000-2001 Western electricity crisis. On its own and then with the new authority that it was granted in the Energy Policy Act of 2005, FERC has issued enforceable rules prohibiting the filing of false information and toughened the standards that the price-reporting services must apply to the transactions that they use to construct index prices in order for the index prices to be used in FERC-jurisdictional tariffs.[22] In addition, the Commodity Futures Trading Commission (CFTC) has investigated vigorously many instances of false reporting to the price-reporting services, presumably leading to improved reliability of data reporting.[23]

4.2 Hourly Load Data

Electric utilities' hourly loads from FERC Form 714 are available with approximately the same spatial resolution as the hourly loads published by RTOs. While the RTO data tend to be available on a near real-time basis, however, the FERC form 714 data are only available with a lag of a year or more. For example, the 2005 data were not yet available as of May 2006. In order to be useful for market monitoring, data similar to the FERC Form 714 data would need to be published and/or made available for this purpose on a much-more timely basis. We do not think that the release of these data closer to real-time would raise genuine and new confidentiality concerns. If a West-wide market monitoring entity were established, access to such hourly load data on a more current basis would be useful. Hopefully access to such information could be negotiated. Temperature data may provide good proxies for load data and are available close to real time.

[21] For example, see http://www.djindexes.com/mdsidx/?event=energyUSHourly.

[22] For example, see http://www.ferc.gov/whats-new/comm-meet/063005/G-15.pdf and http://www.ferc.gov/whats-new/comm-meet/111804/M-1.pdf. Additionally, the Energy Policy Act of 2005 included authority for FERC to issue penalties for false reporting.

[23] For example, see http://www.cftc.gov/opa/enf02/opa4728-02.htm, http://www.cftc.gov/opa/enf03/opa4869-03.htm, and http://www.cftc.gov/opa/enf03/opa4840-03.htm.

4.3 Hydro Data

There are abundant publicly available data on hydrologic conditions in the Pacific Northwest. Given the importance of hydro in the Western grid as a whole and particularly the Pacific Northwest, these data are potentially very useful in understanding wholesale power markets in the West.

4.3.1 Flows and Reservoir Levels

The U.S. Army Corps of Engineers publishes daily data on flows of water and reservoir levels at various points on the Columbia and Snake rivers. These data have been collected on a comparatively easy-to-use web site by the School of Aquatic and Fishery Sciences at the University of Washington.[24] From the data on flow and spill at various dams, it is possible to get relatively accurate estimates of the amount of hydroelectricity generation at a dam on a day, but this information may be difficult to use for market monitoring purposes in that it may reflect response to, rather than the causes of, the market conditions that a market monitor might like to explain.[25] The data on reservoir levels — especially at upstream locations with storage, such as Grand Coulee — are potentially more useful for market monitoring because they are predetermined and hence cannot be influenced by market conditions at a point in time. Reservoir levels are a good proxy for the *potential* to generate hydroelectricity in the future and hence the opportunity cost associated with generating hydroelectricity at a point in time. In a competitive market, lower prices will be associated with higher storage and lower opportunity costs of hydro generation.

4.3.2 Snow Pack

Water can be stored behind a dam as well as in snow pack — that is, as long as temperatures at suitably high elevations remain sufficiently low. The Natural Resources Conservation Service of the U.S. Department of Agriculture collects daily data on snow pack at hundreds of sites throughout the West.[26] Data on snow pack at sites in the relevant hydrologic basins can provide information about the potential to generate hydroelectricity once the snow melts.

4.4 Plant Availability Data

Outages of major generating units can influence prices. Generators routinely report outages to their control area coordinators and to reliability organizations such as the North American Reliability Council (NERC) and its associated regional reliability councils. In the case of data reported to control area operators, the data may not be published publicly at all; and for data reported to NERC and/or regional reliability councils, the data are publicly available only in highly aggregated form. For example, WECC publishes a daily report that contains data on generator outages for three sub-regions of WECC, but the report does not differentiate between

[24] http://www.cbr.washington.edu/dart/river.html

[25] High temperature at high elevations and/or rain during the spring result in runoff and consequent hydroelectric generation, which is essentially exogenous. Data on temperature and rainfall might help disentangle controllable and non-controllable hydroelectric generation (Mitchell 2006).

[26] http://www.wcc.nrcs.usda.gov/snow/

forced and scheduled outages, nor does the report any disaggregation of outages with respect to the efficiency or fuel of the unavailable units.[27] For units in California, the CAISO publishes daily information on unit outages that differentiates between planned and forced outages.[28] In addition, there are commercial services that provide data on unit availability throughout the entire U.S. in real-time.[29]

Public data on the availability of nuclear units are more readily available. Each morning, the Nuclear Regulatory Commission, publishes a report on the availability of all nuclear generating units in the U.S. on that day.[30]

4.5 Continuous Emissions Monitoring System (CEMS) data

As discussed above, data on the hourly operation of large steam units are available from the EPA's Continuous Emissions Monitoring System data. These data are not available for all units and are published with a substantial lag.

4.6 Electric Quarterly Report (EQR) data

FERC has increased the reporting requirements for sales made by generators and marketers pursuant to FERC-granted Market-Based Rate (MBR) authority. Such sales cover most wholesale electric transactions entered into in recent years. MBR sellers are required to report to FERC on a quarterly basis essentially all of their transactions, ranging from short-term imbalance energy transactions to multi-year capacity and energy contracts. FERC makes the data publicly available.[31] Because these data are published with a lag of at least a few months, they cannot be used for near real-time market monitoring. To the extent that a substantial fraction of short-term transactions in the West are for standard products delivered to major trading hubs, these EQR data provide relatively little incremental information about prices relative to index prices that are published without a lag. However, the EQR data can be used to validate index prices after the fact and to glean information about prices for transactions beyond the standard products followed by the price-reporting services.

[27] The report is available on http://www.wecc.biz/index.php?module=pagesetter&tid=8&pubcnt=14&orderby=core.created:desc.
[28] http://www.caiso.com/unitstatus/index.html

[29] http://www.genscape.com/na/data_us_morning.shtml

[30] http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/ps.html

[31] http://www.ferc.gov/docs-filing/eqr/data.asp

5. Test of an Econometric Model of Bilateral Power Prices in the West

In this section, we investigate the usefulness of publicly available data for West-wide market monitoring using one particular analytic technique from among those described above. Specifically, we attempt to develop econometric models of a commonly traded product — day-ahead on-peak strips — at two large trading hubs in the West: Mid-Columbia and Palo Verde.

5.1 Functional Form of an Econometric Model

Specifying the functional form of an econometric model is essential to using this technique — and inherently subjective. Functional form describes the mathematical relationship between the variable of interest, i.e., the dependent variable, and the factors that influence the dependent variable, i.e., the independent variables. A simplified functional form of an econometric model is shown below, with "X" showing the independent variable, "Y" denoting the dependent variable, and "a" and "b" as the coefficients that describe the relationship between X and Y.

$$Y = a + bX$$

Numerical methods are used to find the coefficients that best fit the data. These numerical methods also produce estimates of the precision of the estimated coefficients and measures of how much of the variation in the dependent variable is explained by the econometric model.

At a minimum, the functional form of an econometric model should be tied at least loosely to economic theory. In competitive power markets, prices are related to the marginal cost of generation, i.e., the incremental cost of the last unit required to serve load (and reserve requirements). As load and as fuel prices rise, the cost of the marginal generating unit rises as well. If the relative costs of different fuels change, in some cases, the identity of the marginal unit may change as well. In addition, as the quantity of electricity generated at a point in time increases, the price of power should increase as less efficient units using more expensive fuels become marginal.

Our understanding of the relationship between wholesale electricity prices and the marginal cost of production leads us to select a functional form that is non-linear, namely one in which the natural logarithm of price is explained by a series of variables. We estimate models of the natural logarithm of price rather than the level of price for several reasons. First, supply curves in most wholesale power markets tend to be non-linear. An increase in load tends to result in much larger price increases when prices are already high than if they are comparatively low. Estimating a model of log price allows us to capture some of this non-linearity. Second, during on-peak hours in the Western power market, natural gas is almost always the fuel that is being used by the last power plant dispatched to meet load requirements (i.e., gas is "on the margin"). The relationship between power prices and gas prices in a market in which gas is always on the margin is inherently log-log. If gas is on the margin and the market is competitive, the clearing price is the product of the marginal generating unit's heat rate (its efficiency in converting gas to power) and the gas price. In other words:

$$\text{power price} = \text{marginal heat rate} * \text{gas price}$$

Taking logs of both sides yields:

$$\log(\text{power price}) = \log(\text{marginal heat rate}) + \log(\text{gas price})$$

Our econometric models are based on this simple relationship. The challenge is developing data that help us identify the marginal heat rate. We will discuss some of the factors that might determine the marginal heat rate below. Ultimately, we estimate versions of the model including some or all of the variables in the following specification:

$$\begin{aligned}\log(\text{powerprice}) = \alpha + \beta_1 \log(\text{gasprice}) + \beta_2 \text{load} + {} \\ \beta_3 \text{availability of nuclear plants} + {} \\ \delta^* \text{hydro conditions} + {} \\ \gamma^* \text{seasonal and day-of-week dummies} + e\end{aligned}$$

where, *e* is an error term reflecting the portion of the power price not explained by the variables included in our model. Conditional on a certain gas-fired unit being marginal, an increase in the gas price raises the price of power. The other variables in the model essentially determine the efficiency of the marginal unit. For example, if load is higher, the efficiency of the marginal unit is likely to be lower and prices higher. Conversely, if hydro and nuclear generation is more readily available, the efficiency of the marginal unit is likely to be higher and prices lower. In some specifications, we also include dummy variables designed to capture regular variation in power prices over the course of a year and during a week. Below, we discuss the impact and interpretation of each of these factors in our model.

We also must be mindful of the fact that natural gas is not necessarily always on the margin. For example, peak prices cover a 16-hour period. Coal may be marginal in at least some hours of the peak period. Under these conditions, gas prices should not influence clearing prices during those hours. In this case, our specification above would bias our estimated coefficient for the gas price downwards. This can be explained in the following way. In an all-gas electric system, a 1% increase in the gas price should lead to a 1% increase in wholesale power prices under all conditions. In other words, the elasticity of the power price with respect to the gas price should be unity. To the extent that the gas price only influences power prices under certain conditions, the estimated elasticity of the power price with respect to the gas price should be less than unity.

5.2 Treating Issues of Geography in the Western Power Markets

One of the most challenging aspects of the analysis of wholesale power markets is the fact that geographic markets are transient, and depend on complex real-time relationships among loads and generation in different locations and power flows around the system. For example, under certain conditions, the entire West may behave as essentially one integrated market with minimal price differences between different locations. This would typically occur when there are no or minimal transmission constraints that cause out-of-merit order dispatch of plants to maintain secure system operations. Under other conditions, transmission constraints may limit the flows of electricity between regions, require some units to be dispatched out of merit order, produce price differences among regions, and hence limit price convergence.

In our scoping analyses, we have adopted a practical and relatively expansive view of geographic markets that we believe reflects the empirical reality of power flows and trade in the West. We assume that supply and demand conditions in California influence prices at both Mid-Columbia and Palo Verde, but that factors in the Desert Southwest do not have a direct impact on prices in the Pacific Northwest and vice versa. These assumptions reflect the fact that the Pacific Northwest and Desert Southwest are both connected by major transmission lines to California. However, the direct connections between the Pacific Northwest and Desert Southwest are much less robust. In section 5.7, we present some attempts to address the potential for transmission congestion in the econometric analysis.

5.3 Sample Period

Our analysis focuses on the 2002-2004 calendar years. Econometric models are only valid to the extent that major structural changes can be quantified and captured in the models. Consequently, we have chosen to focus on a period of comparatively stable market institutions and supply and demand conditions following the Western electricity crisis of 2000-2001.

5.4 Selection of Variables and Sources of Data

In this section, we discuss the sources of each of the variables included in our econometric model.

5.4.1 On-peak Power Prices

We estimate models of standard day-ahead, on-peak sixteen-hour strips of power for delivery to the Mid-Columbia and Palo Verde trading hubs and rely on the index prices compiled by Bloomberg. In our experience, these prices are consistent with the index prices of other publishers, such as Dow Jones and Platts.

5.4.2 Natural Gas Prices

We use gas prices from Natural Gas Intelligence (NGI) for a variety of locations in the West. Because we do not model or know the specific location of the marginal gas-fired resource in each period, we use gas prices that, we expect, more often than not, correspond to the location of the marginal resource. For example, we use a price reported for the Malin location, in our Mid-Columbia regression. Malin is close to the California-Oregon border and the Malin price tends to track prices throughout the Pacific Northwest as well as prices in Northern California.[32] For Palo Verde, we use a Southern California border price. This price overstates the price of gas for generators in Nevada and Arizona. Under the types of conditions experienced during the 2000-2001 electricity crisis, when prices for delivery into Southern California were significantly higher than for delivery to other nearby locations, the overstatement may be significant. Given that we estimate our models on post-crisis data, we think that Southern California border price is a reasonable proxy for gas prices in both the Desert Southwest and Southern California.

[32] We are familiar with other studies of Northwest power prices that use Sumas or AECO prices.

5.4.3 Hourly Load Data

Next to fuel prices, perhaps the biggest driver of wholesale power prices is load level. For the regressions in our analysis, it is sufficient to use load measures that are reasonably highly correlated with aggregate loads throughout the relevant region, i.e., it is not necessary to construct a comprehensive measure of regional load. We construct daily average loads for three areas: a large utility in the Pacific Northwest (PacifiCorp which includes both the PP&L and Utah Power portions of PacifiCorp)[33]; a large utility in the Desert Southwest (Arizona Public Service); and the California ISO control area. For each utility or control area, we used the hourly loads reported on FERC Form 714.

5.4.4 Month, Day-of-week, and Annual Dummies

Wholesale power prices exhibit certain regular temporal patterns. We include a set of "dummy variables" designed to capture this regular temporal variation.[34] For example, prices tend to be higher in the summer than in the winter. We include a set of month dummies to capture regular seasonal variation in prices. In addition, because so-called day-ahead prices are not always literally for delivery the next day, there may be variations in prices due to the day of the week. For example, during most weeks, the "day-ahead" package traded on Thursday is for delivery on both Friday and Saturday. Because the price reflects an average of weekend and non-weekend prices, the package price tends to be lower than what a Friday-only price might be and above what a Saturday-only price might be. Finally, we include a set of year dummies to reflect the fact that factors that change with lower frequency, such as the stock of generating capacity, may be changing the relationship between the variables that we include in our model and price.

5.4.5 Hydropower Conditions

Hydro conditions are a large driver of prices in the Pacific Northwest. The difficulty in modeling hydro is that while its direct costs are low, generating hydroelectricity entails opportunity costs. Using stored water to generate hydroelectricity today precludes using it in the future. To the extent that the water that is stored behind dams or in snow that has yet to melt is more abundant, the opportunity cost of water is lower, and more hydroelectricity is likely to be supplied at any given price. We capture the amount of water in storage using two different measures.

First, we model reservoir levels at Grand Coulee. We believe that Grand Coulee reservoir levels are a good measure of the availability of hydroelectricity from the entire Columbia River system because there is a large amount of storage behind Grand Coulee and it is upstream of most of the largest dams on the Columbia River. We measure reservoir levels as the ratio of the reservoir

[33] It may not be optimal to use a load variable that reflects Utah Power load in our analysis. Utah Power is more closely integrated with the Desert Southwest than the Pacific Northwest. Future work should probably use a broader aggregate of Pacific Northwest load or use the load of a different Pacific Northwest utility as a proxy for load throughout the region (Mitchell 2006).

[34] A "dummy" or "indicator" variable captures the fact that an observation meets a certain specific logical condition. For example, a "June dummy" would be one for all observations corresponding to June delivery dates and zero otherwise.

level on a specific day to the ten-year average reservoir level for the relevant date.[35] In effect, by specifying the variable in this way, we de-seasonalize the data to account for the regular variation in reservoir levels, i.e., the depletion of the reservoir over the winter and spring, the fill during the spring and early summer run-off, and relatively flat reservoir levels during the fall.

Second, we model snow pack levels at one location in the Cascades.[36] This measure of snow pack is a proxy for the snow pack throughout the Columbia River basin. Our raw data contain information on snow pack in water-inch equivalents. The measure that we include in our regression is the log of the difference between the level of snow pack on a specific date and the five-year average for the same date.[37] We use this measure rather than a ratio of actual to average snow pack, because snow pack naturally declines virtually to zero each year in this area. A ratio of actual to average snow pack gives undue weight to small deviations in snow pack in the late spring/early summer when most of the snow has melted.

5.4.6 Outages of Nuclear Generators

Outages of major base-load generators are akin to load in terms of their effect on the efficiency of the marginal unit in a given hour. An outage of a generating unit that would otherwise run in merit order necessitates the use of higher cost resources to meet load. We have chosen to use nuclear outages as a measure of availability of base-load generators, since nuclear plants almost always operate in base-load mode everywhere they operate.

To reflect nuclear unit outages in our model, we use data from the Nuclear Regulatory Commission to compute a measure of the daily availability of nuclear plants throughout the West. We compute nuclear availability for three distinct geographic locations (the Pacific Northwest, the Desert Southwest, and California), just as we did for load data. The Pacific Northwest measure reflects the availability of the Columbia nuclear power plant. The Desert Southwest measure reflects the availability of the Palo Verde nuclear plant. The California measure reflects the availability of the Diablo Canyon and San Onofre nuclear plants. In aggregate the measures reflect the availability of all nuclear plants in the West.

In theory, outages of other baseload units, such as many coal units, have the same effect on prices as outages of nuclear units. As discussed above, data on nuclear unit outages are publicly available while data on outages of non-nuclear units outside of California are commercially available, but not necessarily in the public domain. We have not attempted to obtain these data and incorporate them in our analysis.

It is potentially important to differentiate changes in nuclear plant availability due to planned nuclear outages from those due to forced outages. Because planned outages are anticipated, generation owners and/or ISO's schedule them to occur during low-price periods and when other major units are not down for maintenance, minimizing the effect of the lost output on price.

[35] The ten-year averages are available from the University of Washington's DART site discussed above in Footnote 24.

[36] The location is Hart's Pass.

[37] We construct five-year averages ourselves.

Because virtually all planned outages occur in the spring and fall, for each geographic measure of nuclear availability we include three different temporal measures, a summer measure, a winter measure, and a spring/fall or shoulder measure.

5.5 Results

We estimate separate regressions for Mid-Columbia and Palo Verde because these are two of the largest trading hubs in the West and in sufficiently different parts of the West that different factors are likely to drive prices at the two locations. We show the results of the ordinary-least squares regressions[38] for these two locations in Tables 1 and 2 respectively.[39]

Before describing the results in technical detail, we make the following observations. In both the Palo Verde and Mid-Columbia regressions, a few key variables — notably, natural gas fuel prices and loads — go a long ways towards explaining wholesale power prices. Other factors, such as nuclear unit outages, have statistically significant effects on prices, but they occur sufficiently rarely that adding variables that capture these factors to the model does little to explain variation in wholesale power prices over long periods of time — even though they may be important to understanding the behavior of prices at a specific point in time.

The results for Palo Verde are shown in Table 1. In general, the factors that we hypothesized should influence power prices do in fact influence power prices. In addition, the magnitudes of the impacts of different factors on power prices are economically plausible. Finally, the models seem to explain a large fraction of the overall variation in power prices. This gives us some confidence that the model is well specified.

Looking at the results in more detail, the first column of Table 1 shows the results of a univariate regression of the log power price on the log natural gas price. Each subsequent column shows the results of a specification that includes more independent variables. Most of the coefficient estimates are intuitive and many are statistically significant at conventional levels of significance.[40] The coefficient on the log of the natural gas price is close to one (e.g., 0.79 to 0.93), as it should be in a market in which gas is on the margin most of the time. In columns 3 and 4 of Table 1, the coefficient estimates on the logs of the Arizona Public Service (APS) and

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[38] Econometric models are estimated using specific numerical techniques. Perhaps the most common technique is ordinary least squares, which involves estimating coefficients so as to minimize the sum of the squared deviations between actual realizations of the dependent variable and the predictions of the model.

[39] We have also estimated versions of the model that modify the standard errors to account for serial correlation, i.e., the fact that certain unobserved factors may influence prices across multiple days and hence each day should not be treated as an independent observation for the purposes of statistical inference. In general the standard errors are larger, but virtually all of the coefficients that are statistically significant in the ordinary least squares model are still statistically significant with the modified standard errors. We have not adjusted the power price data so that it is consistent with the WECC pre-scheduling calendar, i.e., we treat every week as if it is normal and excludes holidays.

[40] A t-statistic in excess of ~1.96 in absolute value indicates that, assuming that the true coefficient is in fact zero, that a coefficient equal to or greater than the observed coefficient in absolute value would be observed due to random chance with only 5% probability, i.e., the coefficient is statistically significant at the 5% significance level. T-statistics that meet this criterion are marked with one or two asterisks. Two asterisks indicate that the coefficient is statistically significant at the 1% significance level.

CAISO loads are large and statistically significant. These estimates suggest that a 10% increase in either the Southwest or California load approximately leads to a 5% increase in price.

As expected, the nuclear variables show that increased nuclear availability lowers prices (see column 4 in Table 1). Somewhat counter-intuitively, Palo Verde nuclear availability lowers prices in the summer and shoulder periods but not in the winter. In contrast, the coefficients on California nuclear availability have the expected signs and are statistically significant for the summer and winter but not for the shoulder period. It could be that differentiating availability by season is not capturing the distinction between planned and unplanned outages in the way that we hoped.

It is interesting that the coefficients on California and Palo Verde nuclear availability for the summer are roughly equal in magnitude. The coefficients of these independent variables suggest that the availability of an additional 1,000 MW nuclear unit leads to approximately a 2% drop in price. The fact that a MW of availability has the same effect on the Palo Verde price regardless of whether it is at Palo Verde or in California suggests that the two markets are tightly integrated.

The month dummies show a counter-intuitive pattern of higher-than-average prices in some summer months in the second regression model and lower-than-average prices in the third and fourth regression model. However, given the other variables in the model, such as load, the interpretation of the month dummies is not straightforward. For example, holding load constant, we might expect lower prices in the summer because maintenance outages are scheduled to maximize the availability of thermal units in the summer. The day-of-week dummies show lower prices on Friday and higher prices on Saturday, as we would expect from the fact that Friday and Saturday are traded as a package. Finally, the year dummies show a downward overall trend decline in prices from 2002-2004, conditional on all other observable variables.

Table 1. Palo Verde regressions

The dependent variable is the log of the PV day-ahead on-peak price.
t-statistics are in parentheses.

	(1)	(2)	(3)	(4)
log of the gas price at the Southern Cal. border	0.795	0.870	0.943	0.936
	(49.75)**	(32.75)**	(40.49)**	(39.85)**
Month dummies:				
February		0.049	0.054	0.042
		(2.78)**	(3.63)**	(2.74)**
March		0.069	0.073	0.141
		(3.96)**	(4.88)**	(1.92)
April		0.006	-0.003	0.038
		(0.35)	(0.19)	(0.53)
May		0.017	-0.092	-0.014
		(0.95)	(5.52)**	(0.19)
June		0.133	-0.106	-0.014
		(7.50)**	(4.98)**	(0.14)
July		0.325	-0.022	0.092
		(18.55)**	(0.87)	(0.89)
August		0.169	-0.149	-0.034
		(9.90)**	(6.34)**	(0.33)
September		0.068	-0.170	-0.089
		(3.89)**	(8.42)**	(1.14)
October		0.053	-0.015	0.016
		(2.98)**	(0.96)	(0.22)
November		-0.020	-0.010	0.040
		(1.11)	(0.62)	(0.56)
December		0.006	-0.060	-0.067
		(0.30)	(3.49)**	(3.67)**
Day-of-week dummmies:				
Tuesday		-0.041	-0.050	-0.050
		(3.30)**	(4.72)**	(4.84)**
Wednesday		-0.029	-0.041	-0.039
		(2.35)*	(3.88)**	(3.84)**
Thursday		-0.032	-0.039	-0.038
		(2.64)**	(3.77)**	(3.74)**
Friday		-0.083	-0.082	-0.081
		(6.77)**	(7.81)**	(7.82)**
Saturday		-0.056	0.013	0.012
		(4.55)**	(1.10)	(1.05)
Year dummies:				
2002		0.022	0.074	0.081
		(1.41)	(5.35)**	(5.72)**
2003		0.000	0.000	0.000
		(.)	(.)	(.)
2004		-0.043	-0.091	-0.096
		(4.78)**	(11.15)**	(10.95)**
Load variables:				
log of APS load			0.486	0.522
			(9.85)**	(10.76)**
log of CAISO load			0.544	0.517
			(6.94)**	(6.73)**
Nuclear variables:				
Availability of the Palo Verde plant (MW)				
Summer				-0.00002
				(2.64)**
Winter				0.00001
				(0.85)
Shoulder				-0.00004
				(5.73)**
Availability of California nuclear plants (MW)				
Summer				-0.00003
				(1.98)*
Winter				-0.00003
				(4.26)**
Shoulder				-0.00000
				(0.01)
Constant	2.567	2.428	-7.053	-6.968
	(106.52)**	(57.86)**	(10.46)**	(10.43)**
Observations	882	882	882	875
R-squared	0.74	0.86	0.90	0.91

* significant at 5%; ** significant at 1%

The Mid-Columbia results are shown in Table 2. These results are somewhat more anomalous and puzzling. While many of the parameter estimates have the expected signs and economically plausible magnitudes, some do not. In particular, the coefficients on gas (which range between 1.2 and 1.5) are higher than economically plausible for a market in which gas is usually on the margin. We discuss some possible explanations of these results related to transmission congestion below in section 5.7.

Dissecting the Mid-Columbia results from a more technical point of view, we offer the following observations. First, the elasticity of the power price with respect to the gas price is greater than one (that is, for every percentage point increase in the gas price, the price of power increases by more than one percent), which is an unexpected and surprising result and suggests that the gas price may be capturing some factor that we have neglected to include in the model. For example, as we discuss in section 5.7, rising gas prices tend to be associated with the end of the sometimes extreme low prices experienced in the Northwest during the spring runoff. Alternatively, the high coefficient on the gas price variable may indicate that the Malin gas price is not a good proxy for the prices actually paid by generators in the Pacific Northwest and Northern California.

Second, the hydro variables (i.e., Grand Coulee reservoir levels and actual vs. typical snow pack) are negative and have the expected signs.

Third, many of the coefficients on the nuclear availability variables are either statistically insignificant or have the wrong signs.[41]

Fourth, similar to the Palo Verde regression results, the pattern of the coefficients on the month dummies is strange, but given all of the other variables in the model that vary by season, including load and at least one of the hydro variables, the interpretation of the month dummies is complicated.

Finally, the day-of-week dummies exhibit the same Friday/Saturday pattern and the year dummies show the same secular decline in prices as in the Palo Verde regression.

Stepping back and looking at the Palo Verde and Mid-Columbia results together provides support for our initial observation that a few key variables (natural gas fuel prices and load levels) provide significant ability to explain power prices. One measure for assessing the fit (or explanatory power) of a model is the R^2 statistic that measures the fraction of the variance of the dependent variable that can be explained by the econometric model. For example, the R^2 for the Palo Verde model that includes the most comprehensive set of independent variables suggests that the model explains 91% of the variations in log prices during the period examined. Interestingly, a univariate regression of the log price on the log gas price explains 74% of the variation in price while including a full set of temporal dummies increases R^2 to 86%. Adding the APS and CAISO load variables increases R^2 to 90%. Adding the remaining variables, even though their coefficients are statistically significant, does little to improve the fit of the model.

[41] One conjecture about the California nuclear coefficients is that the outages of nuclear units in California somehow limits import capability from the Pacific Northwest resulting in more congestion out of the Pacific Northwest and lower prices there.

This pattern of R^2 occurs for at least two reasons: First, key drivers such as fuel prices and loads explain a large fraction of the variation in electric prices. Second, even though other factors, such as nuclear unit outages sometimes have statistically significant effects on prices, they occur sufficiently rarely that adding variables that capture these factors to the model does little to explain variation in prices over long periods of time — even though they may be important to understanding the behavior of prices at a point in time.

The same pattern of relatively few variables explaining a relatively large fraction of the variation in (log) price exists across the Mid-C regressions although it is hard to be as confident in the explanatory power of the same limited set of fundamental variables given some of the counter-intuitive parameter estimates.

Table 2. Mid-Columbia regressions

The dependent variable is the log of the Mid-C day-ahead on-peak price.
t-statistics are in parentheses.

	(1)	(2)	(3)	(4)	(5)
log of the gas price at Malin	1.225	1.405	1.459	1.536	1.514
	(40.13)**	(25.18)**	(26.20)**	(27.57)**	(27.11)**
Month dummies:					
February		0.037	0.062	0.070	0.062
		(0.88)	(1.52)	(1.77)	(1.54)
March		-0.023	0.024	0.052	-0.366
		(0.54)	(0.53)	(1.15)	(2.44)*
April		-0.235	-0.162	-0.030	-0.527
		(5.56)**	(3.07)**	(0.56)	(3.35)**
May		-0.227	-0.218	-0.167	-0.558
		(5.36)**	(4.11)**	(3.22)**	(3.74)**
June		-0.538	-0.655	-0.686	-1.670
		(12.85)**	(13.89)**	(14.97)**	(8.19)**
July		-0.146	-0.433	-0.461	-1.590
		(3.50)**	(8.19)**	(8.99)**	(7.07)**
August		-0.039	-0.282	-0.350	-1.485
		(0.94)	(5.36)**	(6.78)**	(6.61)**
September		-0.007	-0.144	-0.213	-0.673
		(0.16)	(2.47)*	(3.73)**	(4.21)**
October		-0.059	-0.042	-0.124	-0.555
		(1.39)	(0.83)	(2.46)*	(3.57)**
November		-0.098	-0.085	-0.186	-0.579
		(2.22)*	(1.99)*	(4.27)**	(3.83)**
December		-0.165	-0.223	-0.312	-0.271
		(3.58)**	(4.98)**	(6.92)**	(6.23)**
Day-of-week dummmies:					
Tuesday		-0.032	-0.052	-0.054	-0.056
		(1.07)	(1.84)	(1.98)*	(2.17)*
Wednesday		-0.023	-0.047	-0.051	-0.050
		(0.79)	(1.66)	(1.89)	(1.95)
Thursday		-0.036	-0.052	-0.060	-0.059
		(1.25)	(1.87)	(2.21)*	(2.29)*
Friday		-0.093	-0.093	-0.107	-0.104
		(3.15)**	(3.28)**	(3.88)**	(3.99)**
Saturday		-0.058	0.092	0.060	0.070
		(1.96)*	(2.76)**	(1.84)	(2.24)*
Year dummies:					
2002		0.143	0.209	0.086	0.236
		(3.56)**	(5.19)**	(2.48)*	(6.08)**
2003		0.025	0.084	0.000	0.123
		(1.15)	(3.84)**	(.)	(4.85)**
2004		0.000	0.000	-0.178	0.000
		(.)	(.)	(7.15)**	(.)
Load variables:					
log of Pacificorp load			0.531	0.344	0.469
			(2.36)*	(1.57)	(2.23)*
log of CAISO load			1.281	1.147	1.112
			(6.69)**	(6.04)**	(6.07)**
Hydro variables:					
Grand Coulee reservoir level relative to normal				-16.397	-10.434
				(7.82)**	(4.92)**
log the difference between actual and typical snow pack				-0.248	-0.143
				(3.93)**	(2.26)*
Nuclear variables:					
Availability of the Columbia plant (MW)					
Summer					-0.0000
					(0.85)
Winter					-0.0001
					(1.97)*
Shoulder					0.0002
Availability of California nuclear plants (MW)					
Summer					0.0003
					(6.96)**
Winter					0.0000
					(1.90)
Shoulder					0.0001
					(3.64)**
Constant	1.738	1.589	-16.315	4.096	-3.147
	(38.79)**	(16.89)**	(7.55)**	(1.22)	(0.95)
Observations	881	881	881	878	872
R-squared	0.65	0.75	0.77	0.78	0.80

* significant at 5%; ** significant at 1%

5.6 Using Econometric Models to Identify Anomalous Prices

An econometric model may establish a baseline that can be used to assess whether power prices are anomalously high or low. With an econometric model with good explanatory capability, it should be possible to predict prices based on observed fuel prices and other variables. To the extent that prices diverge from the model predictions, they may be deemed anomalous. Anomalous prices may warrant further investigation to determine the cause(s) of such deviations from expected prices. On the other hand, if the model has been poorly specified for one reason or another, one could not be confident that discrepancies between the model's results and observed prices did not arise from shortcomings of the model itself. For example, a model estimated on data from a period with abnormally high prices, due to the exercise of market power or some other factor, may consistently produce predictions significantly above observed prices.

To analyze the quality of our econometric model, we used the coefficient estimates of our most comprehensive models (i.e., column 4 in Table 1 and column 5 in Table 2) to estimate predicted prices. We calculated the variance of the prediction errors, i.e., the differences between the predicted and observed prices. We then examined instances in which the predicted price diverged from the actual price by more than three standard deviations, since this would indicate situations outside of expected bounds of variation.[42] Figure 1 shows predicted log prices, and actual (log) prices for Palo Verde and bands that are three standard deviations above and below our predicted prices.

[42] Yoo and Meroney (2005) do essentially the same thing, but for two differences. First, they use a more complicated econometric model, known as a GARCH model, in which the variance of the error term is allowed to vary over time. Second, they estimate their model on data from one period, and then examine prediction errors that result from applying their model out-of-sample, i.e., to a different set of data than they use to estimate their model. We plan to explore the ability of our models to predict prices out of sample in future work as more data become available. Out-of-sample prediction errors tend to be larger than the in-sample prediction errors that we examine. On the other hand, in GARCH models, the variance of the error term tends to be largest when the realizations of the dependent variable are furthest from the predictions of the model, making it more difficult to find observations that meet Yoo and Meroney's three standard deviation criterion.

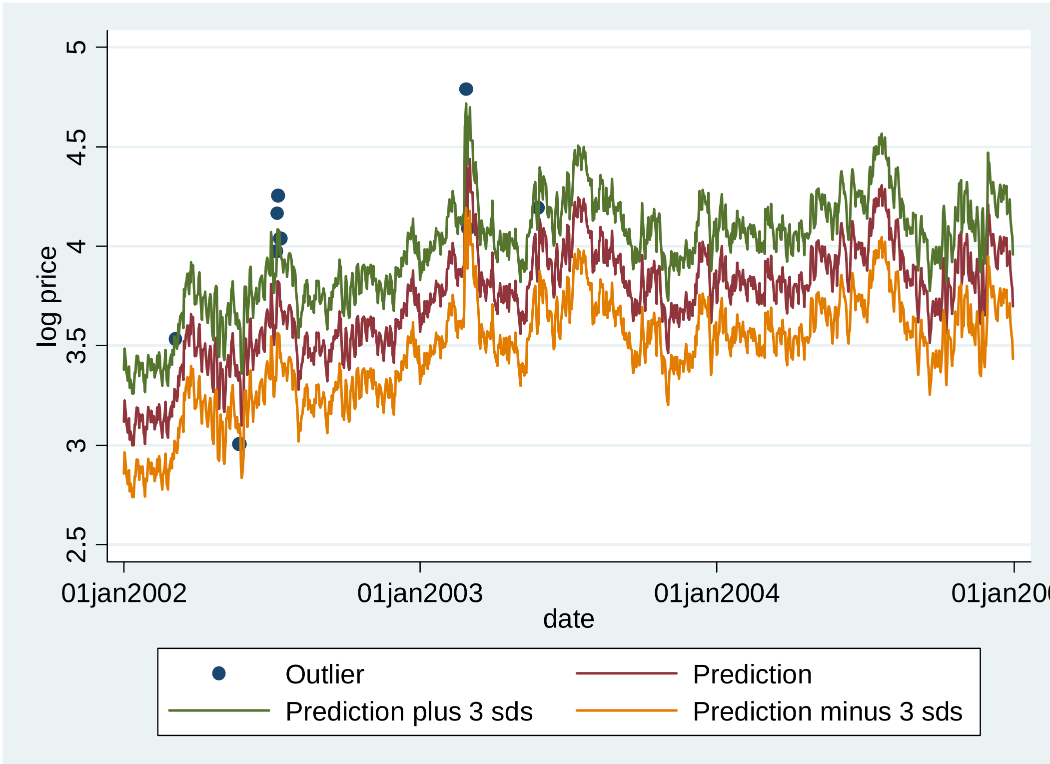

Figure 3. Palo Verde predicted prices, 3-standard error bands, and outliers

The model predictions are shown in purple. Three standard-error bands around the predictions are shown in green and orange. The standard error bands are pretty wide. (Recall that 0.1 in log terms represents approximately a 10% difference in levels.) Assuming that the assumptions used to generate the bands are valid, we would expect prices to fall outside of the bands less than 0.3% of the time. The specific observations that fall outside of the three-standard-error bands are shown as blue dots.

There are a handful of instances in which the actual power price falls outside of the three standard deviation bands. We looked into these instances. The visible price spike in 2002 occurred during the week beginning July 8. There was a heat wave in California combined with outages of major fossil generating units during that week.[43] This suggests that the econometric model may not adequately capture the non-linear relationship between price and load during such genuine shortage conditions. In addition, the model might have fit the prices for that week better if it had included a measure of fossil generator availability — presuming that the outages themselves were legitimate and did not reflect attempts to withhold capacity from the market.[44] Another visible price spike occurred at the end of February 2003, which was a period of very high gas prices. To a certain extent high gas prices should be captured in the model, but the prices that individual generators pay at specific locations and at specific times *within* a day can

[43] *California EnergyMarkets* 2002.

[44] As discussed above, data on fossil generator outages are not as readily available as data on nuclear outages.

diverge significantly from the index prices when gas markets are very tight.[45] There were also unexpected outages of major fossil generating units — including both Mohave units — that week.[46]

Figure 2 shows the same type of information on predicted versus actual power prices for Mid-Columbia. To the extent that there are anomalous prices, they seem to be anomalously low. In all three years of our sample, these downward price spikes occur in June, during the tail end of the spring run-off. This suggests that the combination of our hydro variables and month dummies are not adequately capturing the manner in which water is managed in the Columbia and Snake River basins. For example, it could be that substantial amounts of hydroelectricity are produced in this period because, once reservoirs are full or are on a path so that they are likely to be full by the end of the spring run-off, the opportunity cost of hydroelectricity is zero, i.e., the alternative to generating hydroelectricity is spill at some future date. Our model may not capture this non-linear relationship between reservoir levels and prices.

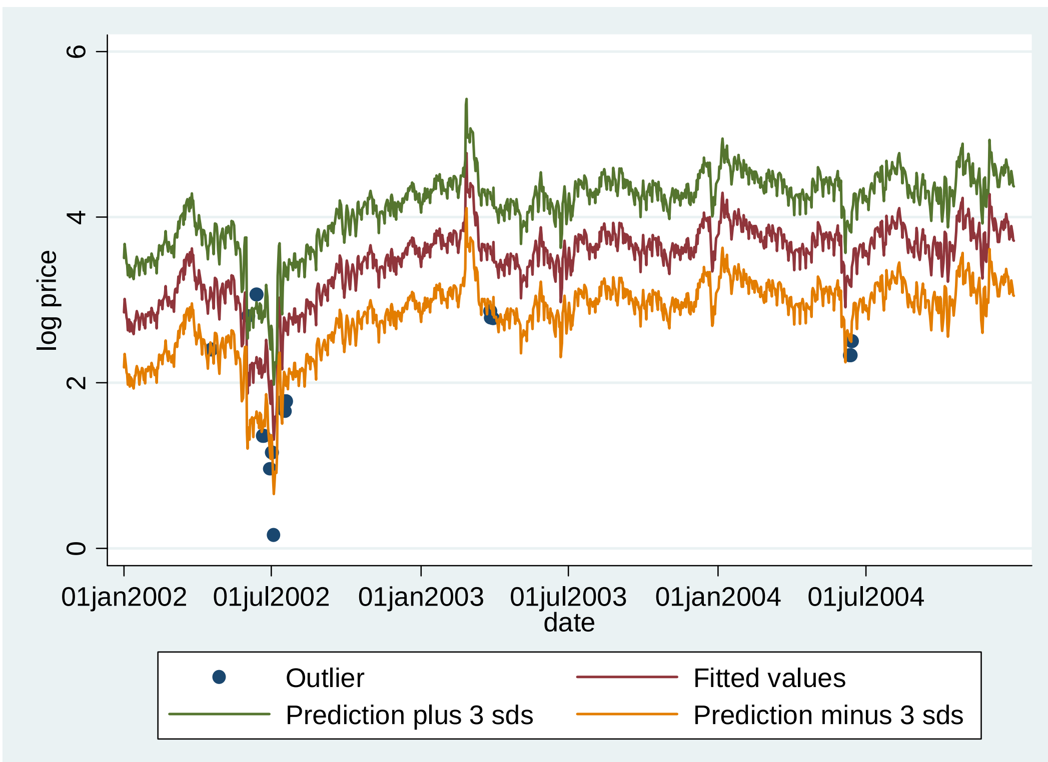

Figure 4. Mid-Columbia predicted prices, 3-standard error bands, and outliers

Notwithstanding the shortcomings of the models, they seem to suggest that simple fundamental models explain a significant fraction of the variation in on-peak power prices during 2002-2004. Some of the most glaring deviations from the predictions of the models potentially are explained

[45] For a discussion of this issues see the summary of FERC's report on the January 2004 gas price spike in New England. (http://www.ferc.gov/EventCalendar/Files/20040524155310-05-24-04-necpuc.pdf)

[46] *California Energy Markets* 2003.

by fundamental factors that have been excluded from the model such as outages of fossil units, or factors that may be not correctly specified (e.g., hydro during the spring run-off period). With this in mind, using well-constructed econometric models to create baseline depictions of "expected prices" could be helpful in identifying prices (or conditions) that fall outside the normal bounds and which deserve further scrutiny from a market monitoring point of view.

5.7 Congestion

Thus far, in our analysis, we have ignored the fact that regional markets tend to separate into sub-regional markets in the presence of transmission congestion. It is important to address the effect of congestion on prices, given that transmission constraints are binding in different parts of the Western power markets at different times over the course of the year.

5.7.1 The Frequency and Magnitude of Congestion in the West

Absent data on physical constraints on the transmission system, congestion is usually inferred from price differences. Inferring congestion from bilateral prices (such as those for major trading hubs in the West) is somewhat subjective. Bilateral contracts frequently trade at a range of prices during the day. If the difference between the bilateral prices at two locations is roughly on a par with the variation in price within a day at one location, the differences across hubs could merely reflect random normal intraday price volatility. In addition, while congestion between two points is a characteristic of a network at a point in time, bilateral contracts cover multi-hour periods during which congestion might arise intermittently. Finally, price differences arise due to transmission tariffs and losses even in the absence of congestion. These factors make it difficult to make precise inferences about congestion from prices alone. Nevertheless, price differences provide some indication of the presence of congestion.

Figure 5 gives some sense for the extent and direction of congestion in the West during the period covered by our analysis. The top portion of Figure 5 shows the distribution of Palo Verde/SP15 (on-peak) price differential for our sample period, i.e., the differential is positive when the PV price is higher. The SP15 price is higher on average, but, with a few minor exceptions, the differential is relatively small, consistent with anecdotal evidence that congestion between the Southwest and Southern California is relatively limited. Of the 880 days for which we have bilateral prices for both locations, the price difference exceeds $5/MWh in absolute value for only 204 days (i.e. 20-25% of the time). The bottom portion of Figure 5 shows the NP15/Mid-Columbia differential. Prices in California at NP15 are almost always higher than prices in the Pacific Northwest and sometimes significantly so, indicating the presence of economically significant congestion of more than intermittent frequency. Of the 843 days for which we have prices for both NP15 and Mid-Columbia, the price difference exceeds $5/MWh for 634 days and $10/MWh for 280 days (i.e. 30% of the time).[47]

[47] Note how these results compare to the very limited geographic price differentials identified by the simulations discussed in the next section. As we discuss in section 6.5.1, the absence of congestion in the simulations is one reason that we question their usefulness for market monitoring.

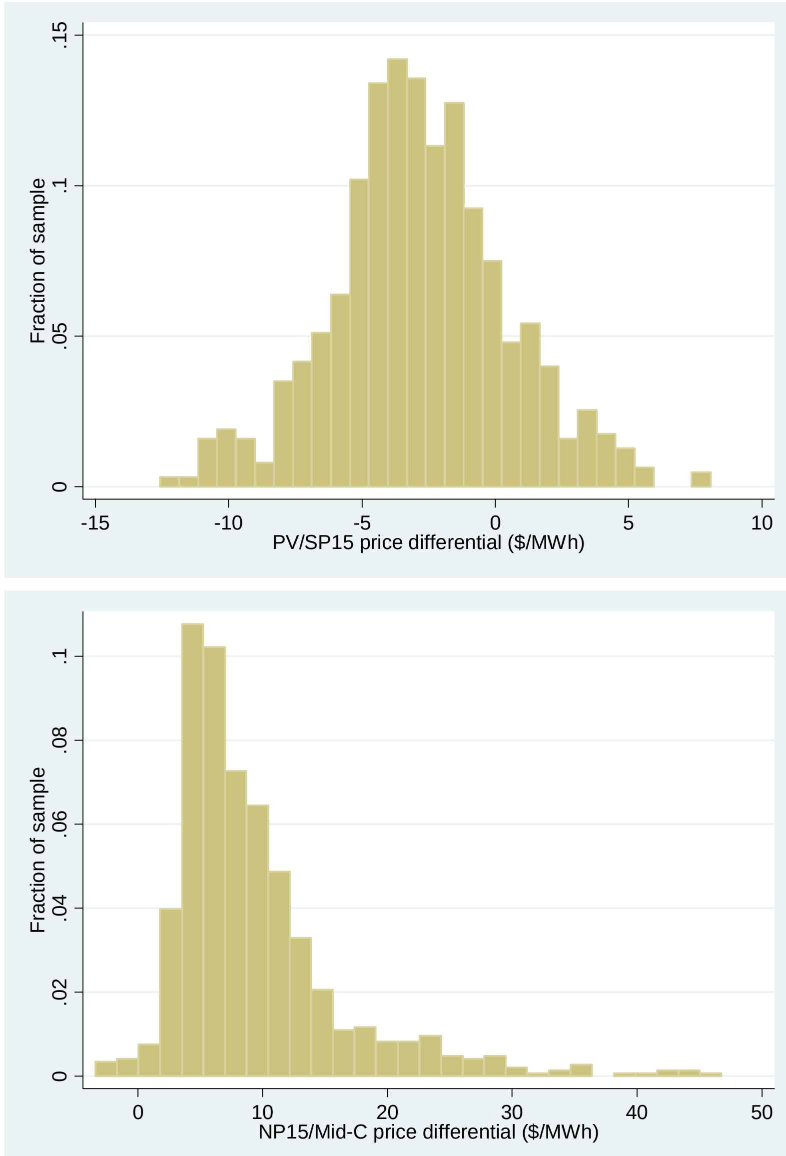

Figure 5. Histograms of PV/SP15 and NP15/Mid-C price differentials

It is also helpful to understand not only the magnitudes of price differentials, but also their distribution across time. Figure 6 shows how the price differentials are distributed across time. The first panel shows that the PV/SP15 price differential is the highest during the summer months when air conditioning loads peak in the Southwest. It is the most negative in the fall. In contrast, the NP15/Mid-C price differential is the most positive in the late spring and early summer, presumably due to the spring run-off, when more hydroelectricity is generated than can be exported readily. It also tends to be large although less so, during the summer when California tends to import large amounts of power from the Pacific Northwest. It is the least positive in the winter when loads peak in the Pacific Northwest.

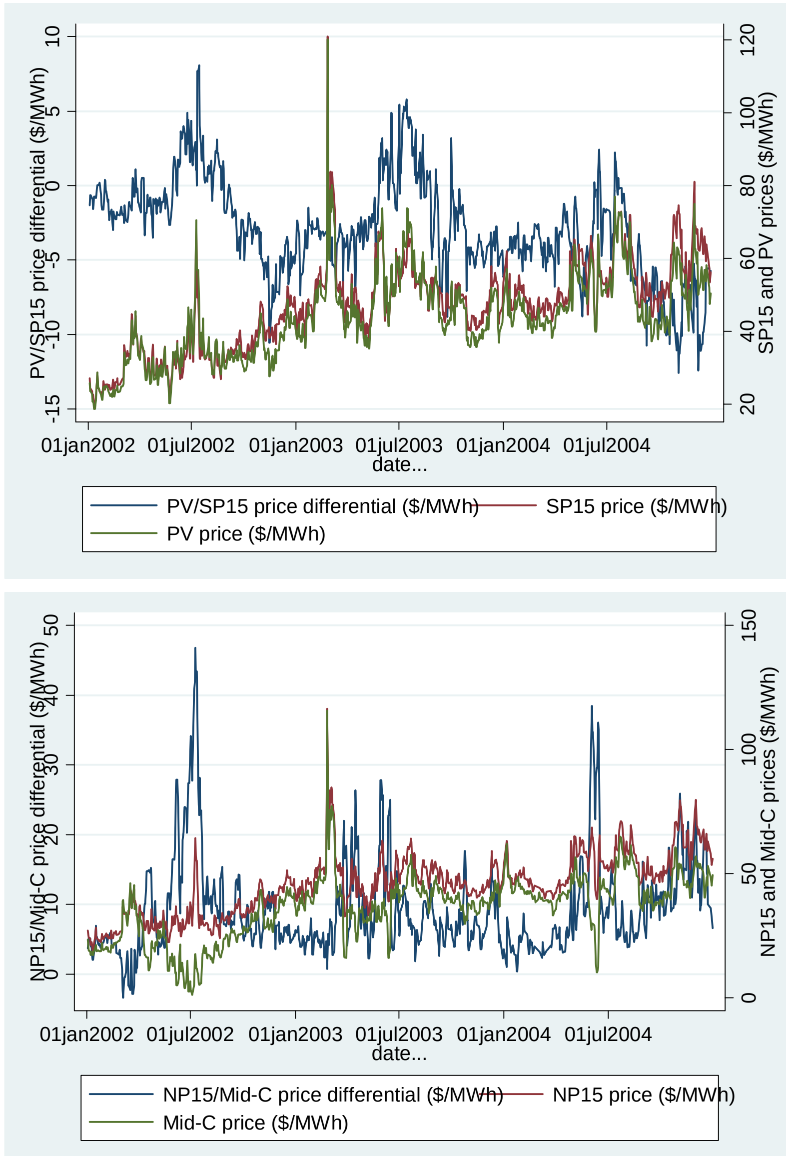

Figure 6. Western price differentials over time

5.7.2 The Theoretical Relationship between Congestion and Prices

Incorporating congestion into an econometric analysis of wholesale prices is tricky. In essence, congestion makes the relationship between prices and certain fundamental variables non-linear in a very specific way.

Consider the following stylized example: there are two adjacent regions, AZ and CA, linked by transmission. There are no losses, the wheeling charge between the two regions is zero, there are no transmission constraints within each region, and the regions are only interconnected with one another, not with any other regions. There are three possible states of transmission congestion between the regions: (1) no congestion, (2) congestion into CA from AZ, and (3) congestion into

AZ from CA. When there is no congestion between the two regions, the two regions constitute one integrated market. The price is determined by the intersection of demand across the whole market and a supply curve reflecting the resources in both regions. If there is congestion into CA from AZ, then any incremental demand in CA has no effect on the price in AZ. In addition, any incremental demand in AZ can only be met with resources that are internal to AZ. This is true until the point where AZ demand rises sufficiently to equalize prices between the two regions If there is congestion into AZ from CA, then incremental demand in AZ can only be met with AZ resources. In addition, demand in CA has no effect on prices in AZ until it rises sufficiently to equalize prices in the two regions.

These relationships are shown graphically in Figure 7 and

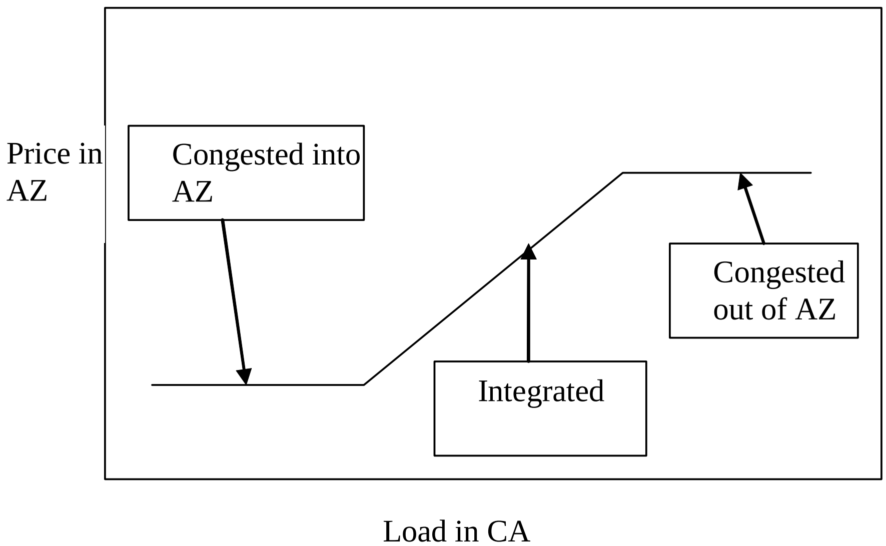

Figure 8. Each figure shows the relationship between price and internal/external load, conditional on the external/internal load remaining constant. For example, the same load in AZ is more likely to result in congestion into AZ when the load in CA is lower, i.e., when load in CA is lower, more low cost resources are available to serve load in AZ and energy is more likely to flow to AZ resulting in congestion into AZ.

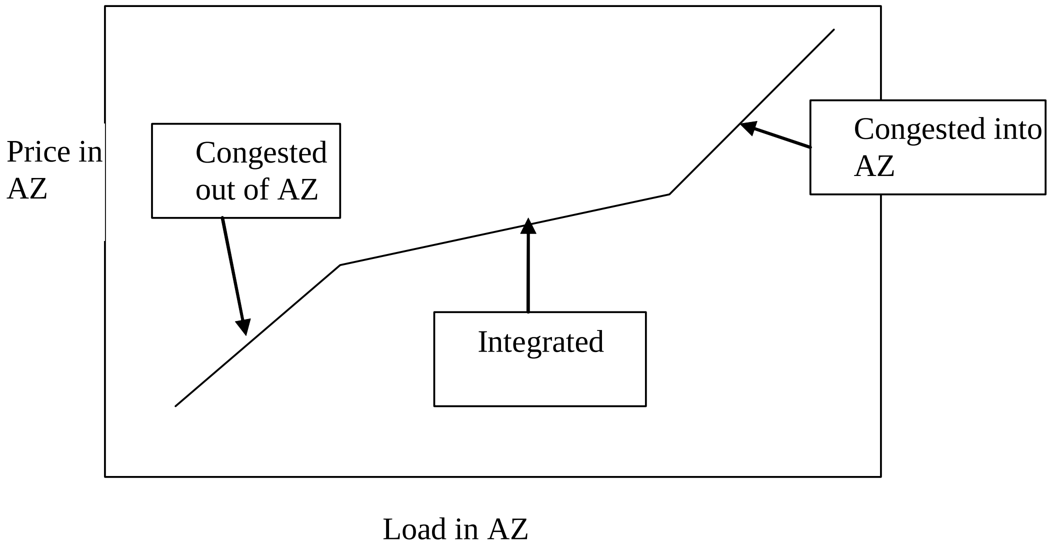

Figure 7. Theoretical relationship between price and internal load (conditional on external load)

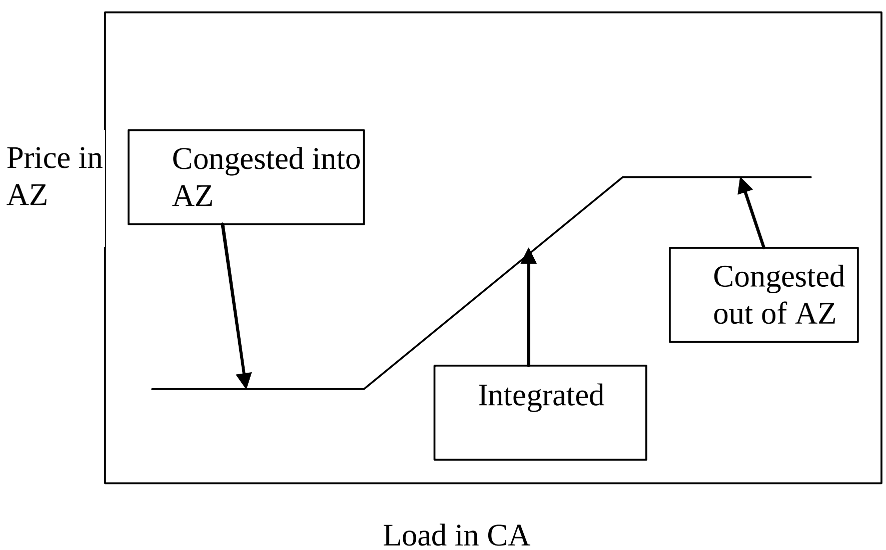

Figure 8. Theoretical relationship between price and external load (conditional on internal load)

5.7.3 Econometric Literature on Congestion

The examples above show how congestion might affect the relationship between price and one fundamental variable, i.e. load. The existing econometric literature does not focus on the effect of congestion on the level of prices per se. Instead, it focuses on estimating the likelihood of the presence and specific direction of congestion and certain parameters such as the cost of losses incurred by moving power from one region to another, the tariffs that traders actually pay, as opposed to the posted tariffs, to move power between regions, and the "shadow value" of transmission in the presence of transmission constraints, i.e., the value of an incremental increase in transmission capacity.

For example, Bailey (1998) applies three distinct techniques to assess the extent to which transmission constraints cause prices at major hubs in the West to separate. The first approach involves modeling correlations between prices at different hubs as functions of different fundamental factors that may lead prices to separate, such as transmission path de-ratings. The second approach attempts to measure the extent to which prices at different locations separate as a function of fundamental factors that tend to be associated with congestion. Using this approach, Bailey is able to develop econometric estimates of the extent of losses and the magnitude of wheeling charges. The last approach involves estimating a "switching model." The switching model is based on the assumption that while prices are observed, transmission tariffs and whether price differences exceed transmission tariffs and hence congestion exists are not directly observed. She estimates that congestion exists between the Pacific Northwest and California during approximately 20 percent of the on-peak periods during which power flows from the Pacific Northwest to California. Kleit and Reitzes (2005) also estimate a switching model. They use their model to estimate the shadow value of transmission between ECAR and PJM and between PJM and the NYISO.

5.7.4 Estimating the Effect of Congestion on Price Levels

The papers cited above are primarily concerned with understanding price differences between regions. In contrast, we are primarily concerned with understanding price *levels* at different locations, while recognizing that transmission congestion potentially influences price levels. One approach might involve estimating a switching model of price levels rather than price differences. In such a model, there would be at least two potential states, one corresponding to integration and another corresponding to congestion. In the congested state, it would be assumed, for example that load in a congested-in area could not influence prices an adjacent congestion-out area. Such a model requires choices of variables that it is assumed influence the probability of the occurrence of a particular state. For example, high load in California combined with low load in the Southwest might increase the probability of congestion from the Southwest into California. When the variables that predict congestion, however, are among the variables that also drive prices, such as loads at various locations, then the switching model is effectively a linear regression model similar to the ones that we have estimated above, but with additional non-linear terms in the variables that both influence prices and are related to congestion. In fact, these non-linear terms should capture exactly the types of non-linearities depicted above in Figure 7 and

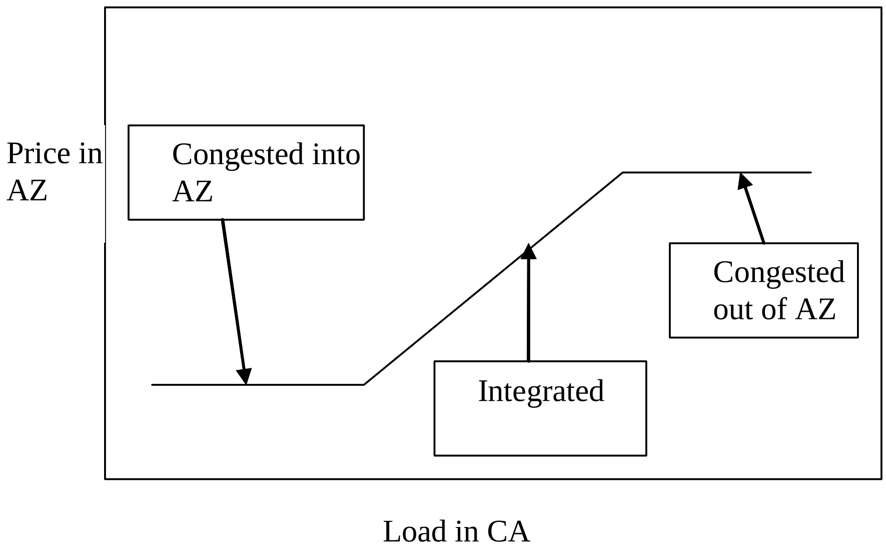

Figure 8.

Alternatively, we could estimate models that allow the relationship between prices and fundamental variables to differ for periods during which there is a strong presumption that congestion occurs. One crude way of analyzing the impact of congestion is to estimate separate models on samples defined by the presence or absence of observed congestion, as measured by price differences between the region of interest and adjoining regions or other similar metrics. The main problem with this approach is that congestion is endogenous, i.e., it is an outcome not a root cause. For example, high load in an area without adequate generation and low load in another area with more than adequate generation might give rise to flows between the areas that lead to congestion. On the other hand, behavior can lead to congestion. For example, withholding in California, in addition to raising prices in California, might cause flows into California that eventually lead to congestion. If congestion results from the behavior that the market monitor is trying to detect, it should not be taken as given in formulating a benchmark by which to assess the competitiveness of a market.

Nevertheless, we present some results based on splitting our sample into observations from congested and un-congested periods. We discuss some potential econometric approaches to the "endogenous congestion" problem below. As discussed above, it is not uncommon for prices in the Pacific Northwest to be extremely low during the spring run-off.[48] When this happens, the Northwest market becomes separated from the California market and California fundamentals should no longer influence Northwest prices on the margin. As a rough attempt to identify these periods, we divide our data into periods in which the market heat rate at Mid-C falls below 6

[48] For example, for most of June and July 2002, prices at Mid-C were below the cost of gas-fired generation and the Columbia nuclear generating station was limited to less than its full output due to abundant hydroelectricity and several major transmission outages on the interfaces between the Northwest and California. See "Southwest Not So Hot; Northwest Not So Wet," *California Energy Markets*, July 26, 2002, 679:3.

MMBtu/MWh and all other periods. We choose this threshold because it reflects a heat rate below that of any gas-fired resource. Given that gas is almost always on the margin in California, a market heat rate below the efficiency of any gas fired resource strongly suggests that the Northwest market is not integrated with the California market. There are econometric issues associated with dividing the sample based on a transformation of the variable that we are trying to explain, namely price. Ideally, we would like to model the fundamental drivers of very low prices in the Northwest rather than condition our analysis on the realization of very low prices. Nevertheless, the following results provide some insight into how the relationship between prices and fundamental variables can change under conditions which lead to congestion out of the Northwest.

Table 3. Mid-C models by market heat rate

Dependent variable is the log of the Mid-C on-peak price		
Models include month and day-of-week dummies	Market heat rate	
	<6	>=6
Log of the Malin gas price	1.808	1.030
	(6.84)**	(32.65)**
Log of PacifiCorp load	0.882	0.471
	(0.98)	(4.15)**
Log of CAISO load	1.052	0.612
	(1.42)	(6.07)**
Grand Coulee reservoir level relative to normal	6.688	-7.354
	(0.68)	(6.48)**
Log the difference between actual and typical snow pack	0.075	-0.208
	(0.14)	(5.62)**
Availability of the Columbia nuclear plant (MW)	0.00029	-0.00004
	(2.46)*	(2.67)**
Availability of California nuclear plants (MW)	0.00005	0.00002
	(0.67)	(2.68)**
Observations	119	753
R-squared	0.82	0.88

Absolute value of t statistics in parentheses
* significant at 5%; ** significant at 1%

The results are interesting and raise a few technical issues that warrant attention when exploring the appropriate way(s) to construct econometric models when the issue is price prediction in Western wholesale power markets. On the one hand, the results for the sample in which the market heat rate is greater than or equal to 6 MMBtu/MWh look relatively "normal." The coefficient on gas is close to one and the coefficients on most of the other variables besides the California nuclear variables have the expected signs. On the other hand, the results for the sample in which the market heat rate is below 6 MMBtu/MWh have no plausible economic interpretation. The coefficient on gas is large even though anecdotal evidence suggests that gas is not on the margin during the days in this sample. In addition, the coefficients on the load variables are much larger than in the other sample. In particular, the coefficient on the log of California load is large even though California load should not drive Northwest prices when the Northwest is congested out.

Given the unexpected character of these results, we strongly suspect that these results reflect "Omitted Variable Bias." This occurs when a variable that is included in the model captures the effect of another variable. In this case, the load and gas price variables that capture the loads and gas prices during the Junes and Julys of our sample tended to rise as the spring run-off ebbed and transmission outages between the Northwest and California were rectified. Perhaps this econometric problem could be addressed by including a variable that captures hydro generation in addition to the variable that we already include that reflects reservoir levels. If we were to include such a variable, we would need to be careful to distinguish between the hydro generation due to the spring run-off that is essentially uncontrollable and exogenous and hydro generation that is the result of economic decisions to use reservoir hydro in response to prices that is endogenous. We are not aware of a clean way to do that given our data. It might be reasonable to assume that all hydroelectricity in May-July is essentially exogenous.

These results also suggest that the results for the full sample, reported in section 5.5, are at least partially driven by data from the period of extreme low prices during the spring runoff in the Northwest. If econometric models such as the ones estimated in this report are to be used for market monitoring, clearly more attention should be given to understanding the price formation process in these periods.

We have had marginally more success identifying the types of non-linear effects of load on price resulting from congestion in our Palo Verde models. The following shows the relationship between the PV/SP15 price differential and the loads in CAISO and APS control areas. The green line shows the price differential, the red dots show CAISO load (normalized so that their scale is roughly similar to that of the APS loads), and the blue dots show APS loads. From the figure, it is easy to see the regular patterns in PV/SP15 price differentials. The PV price tends to rise above the SP15 price only when the Southwest experiences extremely high loads in the summer. For much of the year, the differential hovers in the $0/MWh to -$5/MWh range. It can fall below this range in the winter when APS loads are low so that more low-cost resources from the Southwest are available to serve California loads and hydro availability in both California and the Pacific Northwest is limited. In addition, the dip in the price differential at the end of 2004 corresponds to a period of significant nuclear outages in California.

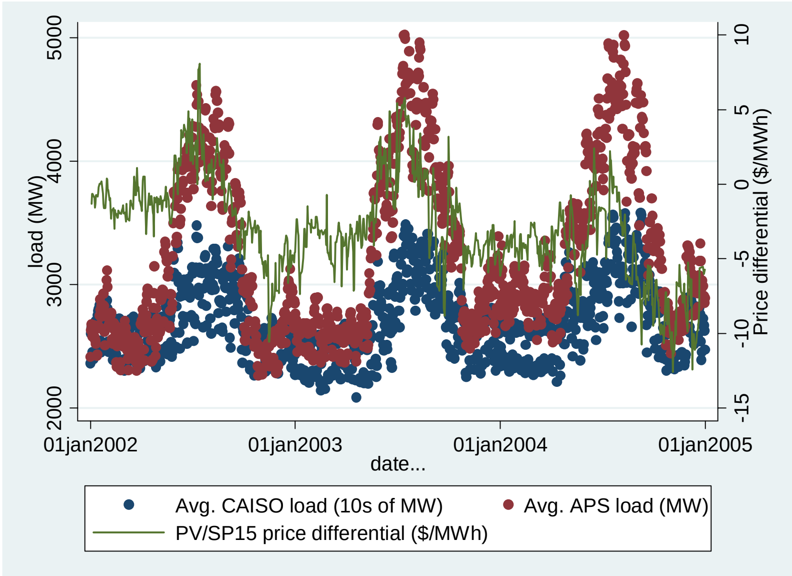

Figure 9. PV/SP15 price differential and CAISO and APS loads

Given the type of pattern that shows up so dramatically in Figure 9, we estimated versions of our model in which the load and nuclear availability variables are allowed to vary depending on whether or not there is congestion. We define days as congested out if the price in SP15 exceeds the Palo Verde price by more than $5/MWh. There are 195 such days in our sample. The results are consistent with the theory described above. When a market is congested out, internal loads and resources have bigger effects on price and external resources have smaller effects on price on the margin. For example, the results below suggest that California loads have essentially no marginal effect on prices on congested out days.[49] The one counter-intuitive result is the coefficient on the interaction between the congestion variable and the California nuclear availability variable; this suggests that California nuclear availability reduces Palo Verde prices by more when there is congestion out of Palo Verde than when no congestion exists.

[49] The sum of the coefficients on log CAISO load and log CAISO load interacted with a congested out dummy is approximately zero.

Table 4. PV regression with congested-out terms

Dependent variable is the log of the PV on-peak price
Models include month and day-of-week dummies

Log of the SoCal border gas price	0.958
	(39.97)**
Congestion out dummy	2.879
	(2.57)*
Log APS load	0.465
	(9.06)**
Cong. out X Log APS Load	0.310
	(3.33)**
Availability of the PV nuclear plant (MW)	-0.00002
	(4.21)**
Cong. out X Availability of the PV nuclear plant (MW)	-0.00003
	(2.07)*
Log CAISO load	0.583
	(7.05)**
Cong. out X Log CAISO load	-0.504
	(3.10)**
Availability of California nuclear plants (MW)	-0.00000
	(0.65)
Cong. out X Availability of California nuclear plants (MW)	-0.00003
	(2.86)**
Observations	873
R-squared	0.91

Absolute value of t statistics in parentheses
* significant at 5%; ** significant at 1%

As discussed above, it could be potentially inappropriate and misleading to treat congestion as exogenous if regressions similar to the ones reported above were to be used for market monitoring. One possible solution to this problem would be to use “instrumental variables” estimation. In “instrumental variables” estimation, regressions similar to the ones above would be estimated. Instead of using direct measures of congestion, the instrumental variables estimates would use predictions of congestion based on fundamental variables that are correlated with congestion, i.e., the so-called “instruments.” The trick is finding good instruments. Good instruments should be correlated with congestion but not subject to the types of manipulation by market participants that the market monitor seeks to detect. For example, transmission outages, to the extent that they are not the result of strategic behavior themselves, may be good instruments to use for congestion. This is one area where additional data could clearly help.[50]

Another approach suggested by Figure 9 is to attempt to identify the configuration of fundamental variables that ultimately lead to congestion. For example, high loads in California and relatively low loads in APS seem to be associated with congestion. The following is a graph

[50] We have not attempted to use OASIS data to identify path deratings, although hourly data on the OTCs and ATCs on major paths into California are available from the CAISO OASIS. WECC’s daily report also contains marginally less detailed data on transmission deratings and outages in a less readily usable form than the CAISO OASIS data.

of the PV/SP15 price differential against the ratio of California load (net of the availability of California nuclear plants) to the APS load.[51] While there is certainly a negative relationship, as might be expected, the relationship is not that tight as might be hoped. For example, there are a significant number of days when the load ratio is relatively low, but the price differentials are still large and negative. We might be able to identify a tighter relationship with additional data on, for example, outages of fossil-fueled generating plants.

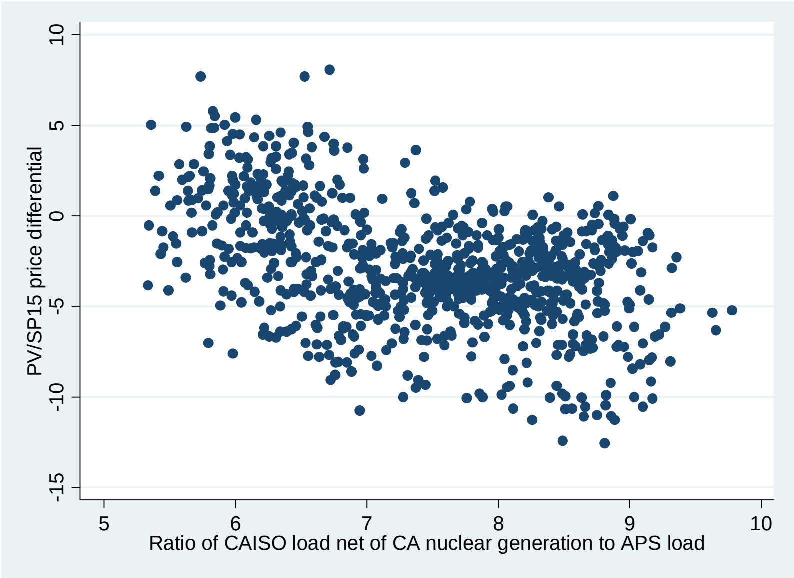

Figure 10. Relationship between PV/SP15 price differential and CAISO/APS load ratio

Congestion has important effects on wholesale prices. Before using econometric models for market monitoring screening purposes, it would be useful to develop more complete characterizations of the effects of the market fundamentals that lead to congestion on wholesale prices in the West—particularly the effect of hydro conditions on congestion out of the Northwest and Northwest wholesale prices.

[51] We do not adjust the APS load to account for the availability of the Palo Verde nuclear generating station. The CAISO load is the vast majority of the load in California and hence netting out a proxy for nuclear generation results in a reasonable approximation of the demand for energy from other sources in California. In contrast, we are using the APS load as a proxy for regional conditions in the Southwest. APS load is a small fraction of all load in the Southwest. Hence, netting out PV nuclear availability from the APS load may provide a misleading measure of broader regional conditions.

6. Using Production Cost Model Simulations of Western Power Markets for Market Monitoring

In this section we discuss a concrete application of production cost modeling techniques for market monitoring (see Section 3.2 for conceptual discussion). One reason for conducting this type of scoping analysis is that production cost models are a widely available analysis tool in the electric industry, and have been used for various market assessment questions in the West as well as more generally in the electricity industry.[52] These models have been used for many years by utilities in planning contexts and in regulatory proceedings covering a variety of topics. Given the lack of market monitoring institutions in the West, the experience of model vendors and users with production cost models provides some institutional and experience base on which market monitoring and assessment activities can build.

In addition, production cost model results provides proxies for the types of detailed operational data to which market monitors in RTOs have access. In the absence of an RTO, it is an open question whether a market monitor could obtain access to these types of rich operational data. To the extent that a West-wide market monitor would not be able to review actual unit commitment and dispatch decisions of control area operators, as company-specific market monitors do (see section 7), running production cost models may provide relatively little incremental value from a market monitoring standpoint.

One approach to applying production cost modeling to market monitoring involves using models with inputs designed to reflect real-time system conditions in order to formulate estimates of near-term competitive prices. This approach to market monitoring is extremely resource-intensive (see Section 3.2). Given limited resources, we decided to use the results of a relatively limited number of simulations of Western power markets based on a few concrete scenarios to understand price formation in the West. It is important to note that these simulations were created as part of a long-run planning effort and were never intended to be used for market monitoring. However, because the simulations were available and produce the types of rich data that are typically available from Day 2 RTO markets, we thought that they were worth exploring. Ultimately, as discussed below, our investigation led us to conclude that the conditions modeled in the production cost simulations seem to be sufficiently far-removed from present and recent historical conditions that they are of limited use for explaining observed prices and therefore may be of limited usefulness for market monitoring purposes.

6.1 Choice of Production Cost Study

We present results based on the GridView model used by the Western Electricity Coordinating Council (WECC) for various regional studies.[53] The data used for this analysis were assembled initially and periodically updated by the Seams Steering Group of the Western Interconnection (SSG-WI). ABB, in conjunction with WECC, has conducted studies for SSG-WI that examined the future transmission system needs of the Western grid under various load and resource

[52] Examples of the use of these models in the west include studies of RTO costs and benefits such as Tabors, Caramanis, and Associates (TCA) 2002 and Henwood (2004).

[53] See http://www.wecc.biz/wrap.php?file=wrap/about.html for background on WECC.

scenarios. These studies report results for two years: 2008 and 2015. Given SSG-WI's familiarity with this model, we wanted to use it as the starting point for our test of production simulation models for market monitoring purposes.

For this project, we contracted with ABB, the GridView vendor, to conduct some simulations and provide detailed output for our analysis. Model vendors, like ABB, typically maintain databases containing many of the inputs to their models. In some cases these databases rely exclusively on publicly available data while, in other cases, proprietary data are used. Appendix A, prepared by ABB, describes the GridView model at a high level and documents key assumptions used in the study.

6.2 Network Representation

One of the starting points for any production cost simulation is to clearly define the area to be studied, along with the internal "topology" or network configuration depicted in the study. The GridView model is a full nodal model. Most of the results that we received were for 33 bubbles, each encompassing many nodes.[54]

Figure 11 shows the aggregated topology for which we received results. As discussed below, the 33 bubble topology does not result in very much congestion as measured by differences in average locational marginal prices across bubbles for the SSG-WI 2008 Base Case. Therefore, for certain sensitivity analyses, a more aggregated topology may be useful, such as the five region aggregation for which results are summarized in Figure 12-Figure 15. There is also value to a level of aggregation that is closer to the state jurisdictional level based upon the interest of state regulators in understanding outcomes at this level.

[54] In modeling the Western Interconnection, the 33 "bubbles" were physically distributed to the 15,000 buses in the transmission network.

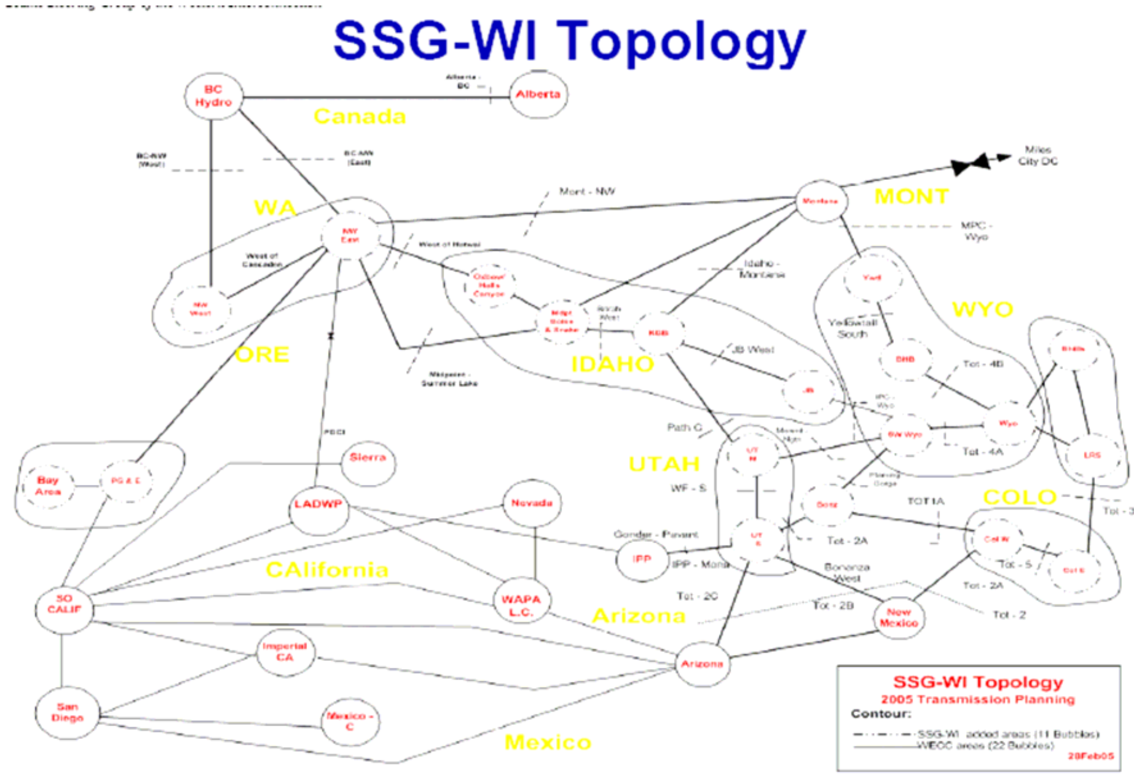

Figure 11. SSG-WI study topology of the Western Grid

6.3 Treatment of Outages

Power plant outages and their treatment in a production simulation model influence the results of the simulation, since assumptions about outages affect the units that are – and are not – assumed to be available for dispatch at any particular time in the modeling period.

Some representation of the expected pattern of forced outages is required for our study, in order for the resulting simulation to be representative of the price that would emerge from the market. It is our understanding that WECC/SSG-WI does not typically incorporate random forced outages in its base case representations, so we needed to adjust the 2008 SSG-WI Base Case to reflect forced outages.

There are two ways that forced outages are typically treated in simulation models. The simplest approximation is the de-rating method. In this approach, generating unit capacity is reduced by the unit's forced outage rate.[55] While easy to implement, the de-rating method produces "too smooth" outcomes that tend to understate the potential impact of forced outages. The main alternative to de-rating is Monte Carlo simulation. In this approach, it is assumed that the availability of each unit at a point in time is a random variable that behaves according to some underlying distribution. For each specific simulation, the availability of each unit at each point

[55] This method is typically used in market power simulations presented to FERC such as the Delivered Price Test and Market Power Screens.

in time is determined by draws from these unit-specific distributions. Multiple simulations with different outage draws are performed and the resulting outcomes are averaged. While Monte Carlo is a superior approach on first principles, it can be burdensome to implement and more complex to explain, especially if each individual simulation is complex.

For market monitoring purposes, neither approach is ideal. The de-rating approach is unlikely to replicate the kind of price spikes that can be associated with the outages of large facilities. Monte Carlo simulation poses implementation difficulties. Our compromise was to have ABB run four outage cases in the hope that we would capture at least some of the extreme conditions that can result from unusual sets of outages.

6.4 Regional Coordination of Operation

Regional coordination of operations is an important issue in the US electricity industry. Coordination problems were at least partly responsible for the large-scale 2003 blackout in the Eastern Interconnection. In RTOs with a large geographic footprint, such as PJM and MISO, regional operations within the RTO can be coordinated, even if there are still potential problems across RTOs. The West, by contrast, has fewer institutional arrangements to achieve coordination of operations. Bilateral interaction among control areas is the primary mode of operation. When it comes to modeling this institutional reality, some care must be taken in choosing a representation that reflects the comparative lack of operational integration in the region.

6.4.1 Unit Commitment

One important aspect of modeling coordination relates to the specification of unit commitment across large regions with multiple control areas. Unit commitment is that part of the scheduling and dispatch process within a single control area that deals, among other things, with the “slow start” property of large steam turbine generators. A unit commitment schedule is developed on a daily and weekly basis to decide how many steam turbines should be started and when they should be shut down in light of projected demand forecasts. This problem requires sophisticated software even in the case of a single control area. When multiple control areas are engaged in regional trade, as in the West, the coordination of unit commitment is unlikely to be perfect. Indeed, one of the perceived benefits of RTOs is the consolidation of multiple control areas to achieve economies that are not otherwise possible. One of these economies is the co-ordination of reserves through an optimal unit commitment.[56] In addition, even when coordination is perfect, unit commitment in the real world involves uncertainty. Unit commitment, by its nature, takes place before system conditions are fully known. Realized conditions may turn out to be very different from the conditions that were expected at the time that units were committed.

Models like GridView are often run under perfect information assumptions, i.e., the models assume that future conditions are known with certainty when units are committed. The result of perfect information assumptions is relatively smooth prices with comparatively little price volatility. Our goal in specifying the assumptions to be used in GridView was to reflect, in some

[56] See Midwest ISO (2006).

reasonable fashion, the lack of complete co-ordination and perfect foresight in unit commitment that we believe is more representative of the actual operation of the Western system. We illustrate how modeling choices affect price volatility by contrasting two GridView cases below. In each case we asked ABB to use "imperfect unit commitment." This was achieved by assuming that only a subset of all transmission constraints that might materialize at the dispatch phase are recognized at the unit commitment phase. When too few units are committed in specific areas because the model fails to anticipate certain transmission constraints, prices go up in those areas because expensive fast start units must be used to meet load instead of cheaper slow start units.[57]

6.4.2 Transmission Losses

A second important modeling issue involves the treatment of marginal transmission losses. By the laws of physics, marginal transmission losses are twice the level of average losses. The load forecasts used in the simulations have average losses embedded in them. GridView gives the user the option of invoking adjustments for marginal losses or not. If the marginal loss adjustment is invoked, it is our understanding that the GridView model then commits extra resources to meet these additional requirements. This has the effect of undoing the imperfect unit commitment described above.

To determine the relative importance of these issues in our simulations, we did several sensitivity analyses focused on these issues. Figure 12 and Figure 13 below reflect the price results for various regions in the West for the case in which an adjustment is made for marginal losses. These figures show the marginal prices for every hour of the 2008 simulated year and are aggregated into five sub-regions: Canada (Alberta and British Columbia); the Northwest Power Pool (NWPP), including Oregon, Washington and Idaho; the Rocky Mountain Power Pool (RMPP), including Montana, Wyoming and Colorado; Arizona, New Mexico and Nevada; and the California ISO. These cases, based on $5/MMBtu gas prices, show very few price spikes in the California ISO (CAISO) region relative to recent experience.

[57] These relationships are illustrated in a related setting in Kahn (1995). This paper shows that when simulation modeling is used in a setting where multiple parties with divergent interests participate, modeling variables like the commitment target will be selected strategically.

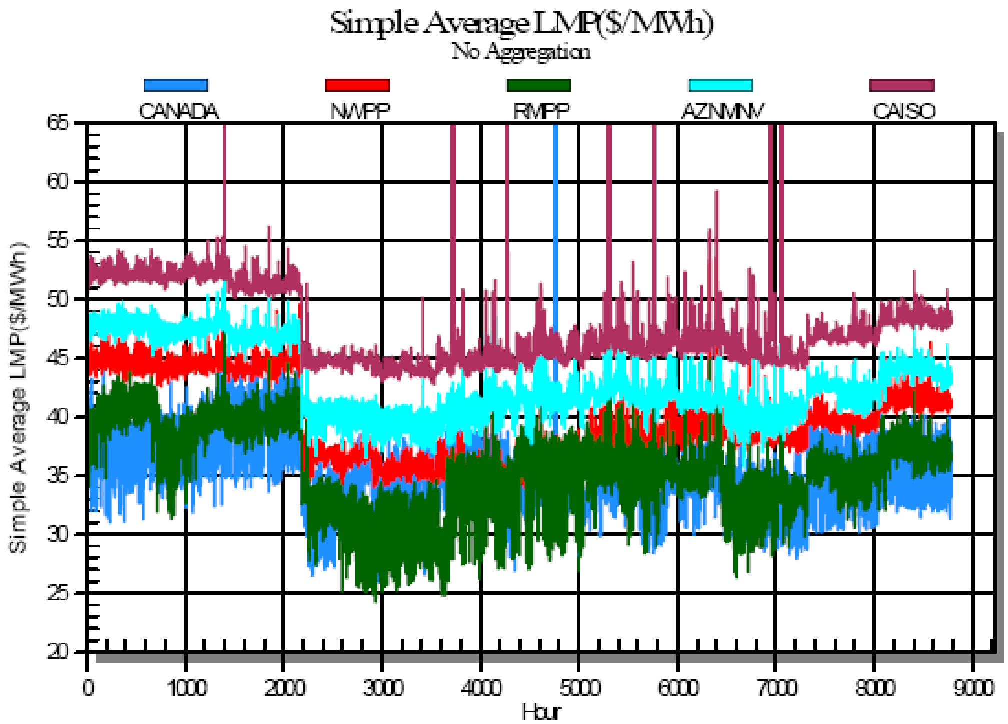

Figure 12. Simulated prices with marginal losses

Figure 13 represents the same data as Figure 12 but in the form of a price duration curve.

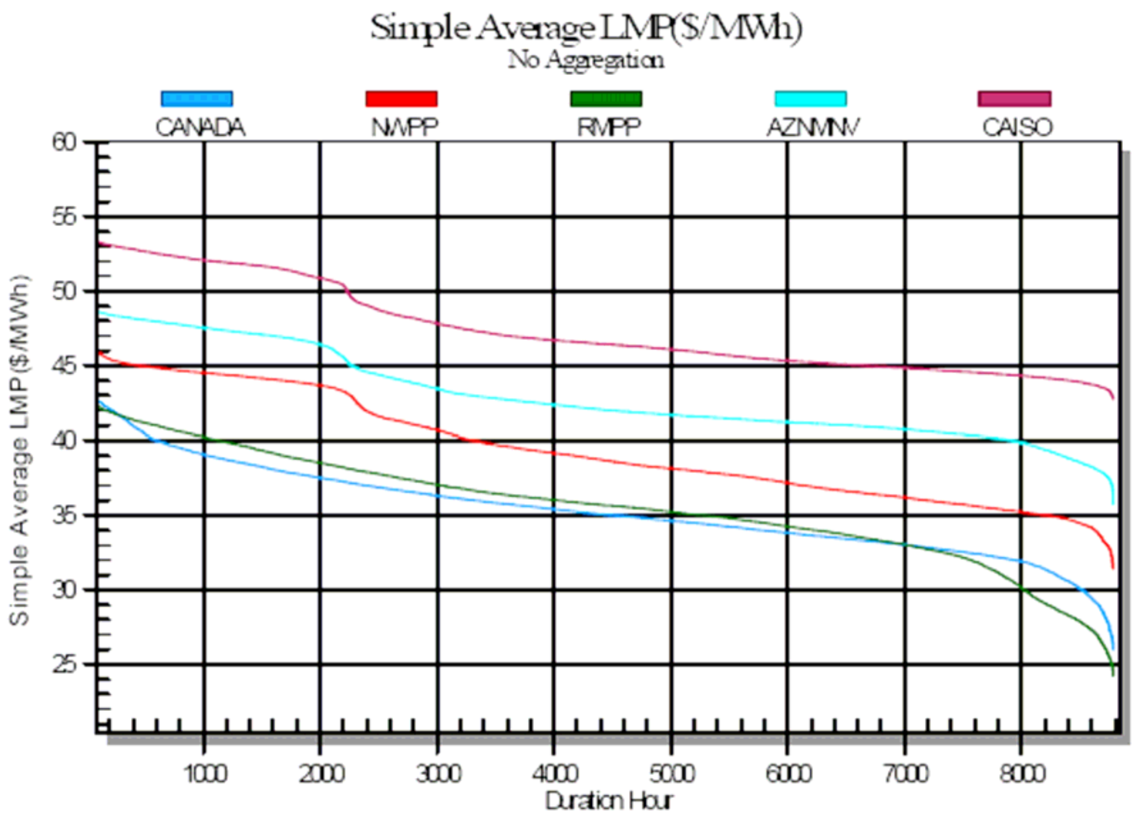

Figure 13. Price duration curve from simulation with marginal losses

Figure 14 and Figure 15 are exactly the same cases as shown in Figure 12 and Figure 13; the only difference is that the marginal loss option is turned off in these simulations. The result is more and higher price spikes (note that the scale in Figure 14 goes to $90/MWh as opposed to $65/MWh in Figure 12). Figure 15 shows that the price spikes are confined to less than 500 hours. During these hours, high cost fast start units must typically be operated in load pockets. Even the prices in the simulations without marginal losses do not reach the levels actually observed in day-ahead on-peak strips, which cover multiple hours and hence, due to averaging, should be lower than the hourly prices reflected in Figure 15, conditional on fuel prices and other variables.

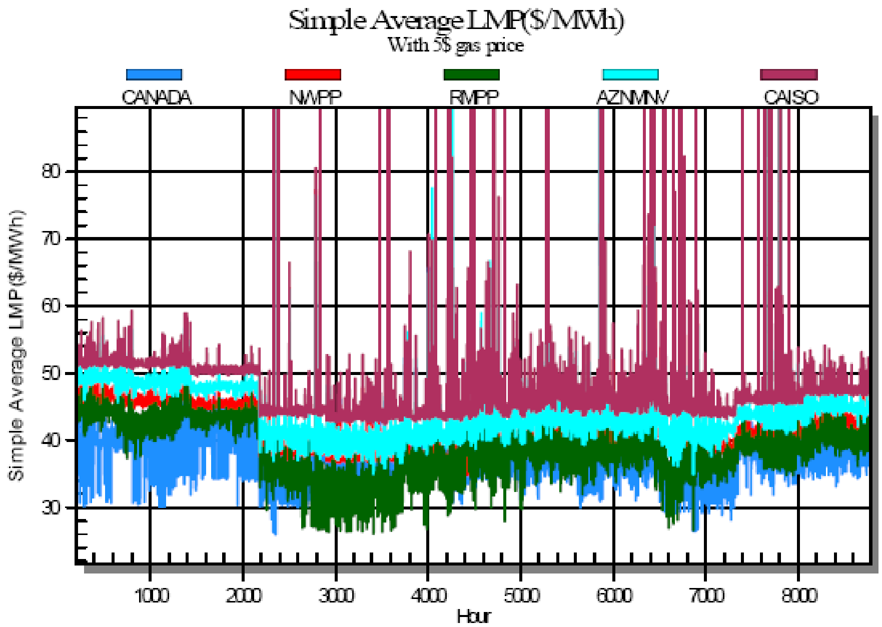

Figure 14. Simulated prices without marginal losses

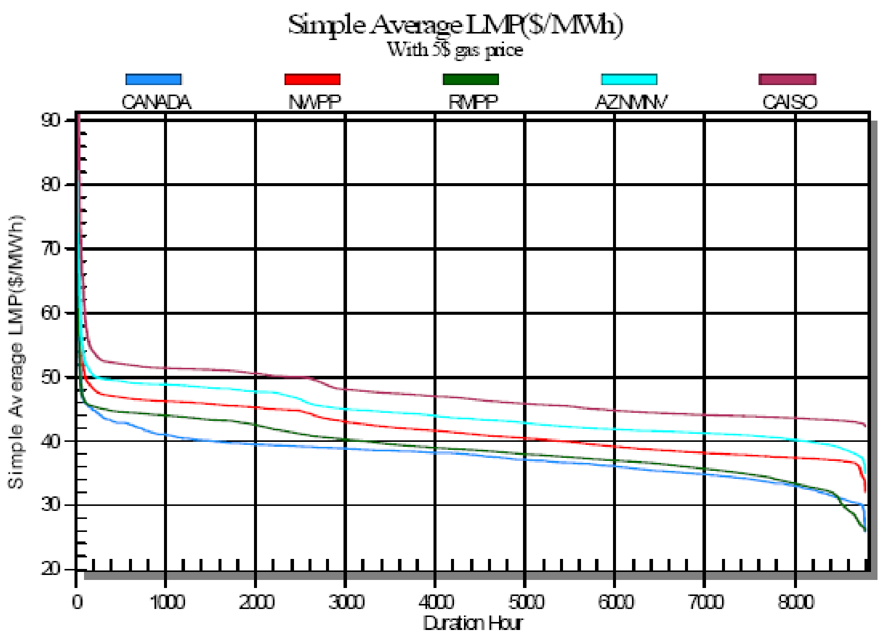

Figure 15. Price duration curve from simulation without marginal losses

While we have no way of determining that the simulations behind Figure 14 and Figure 15 are "right" in any absolute sense, we feel strongly that the simulations behind Figure 12 and Figure 13 are clearly not realistic; thus, we focus on the "marginal losses turned off" simulations in the remainder of this section. The "too smooth" outcomes in the "marginal losses turned on" simulations reflect an ubiquitous, but under-recognized phenomenon in numerical modeling that has recently been called "the optimizer's curse."[58] The basic idea is that mathematical tools applied to uncertain circumstances tend to find solutions that represent the most optimistic outcome, not the most likely one. There are many variations on this theme, and it occurs in a wide variety of contexts.[59] In the context of modeling Western electricity markets, there are many sources of co-ordination inefficiencies and probably even more ways to represent them in a simulation context. We cannot, in our current state of knowledge, be very certain about the proper way to take these factors into account. Since our exercise with simulation modeling is only focused on feasibility issues, the deeper question concerning modeling accuracy cannot be addressed. All we are looking for in a test case is a set of simulations that are qualitatively plausible.

6.5 Discussion of Detailed Production Cost Simulation Results

Using GridView with the SSG-WI 2008 Base Case as the starting point and incorporating the "no marginal losses approach" described above, we examined the results of two different types of simulations. First, we examined the results of simulations in which there are no forced outages and gas prices vary across the simulations. Second, we examined the results of simulations in which gas prices were fixed, but each simulation differed with respect to the specific forced outages that were modeled.

Taken as a whole, it is hard to reconcile the results of these simulations with observed prices in the West. We conclude that these simulations have limited value for market monitoring screening, at least for the near future, for several reasons. First, in the regions that are the most directly relevant to the analysis of wholesale prices, e.g., Arizona—the location of the Palo Verde hub, the prices produced by the simulation seem to vary in a relatively narrow range that suggests that some gas-fired resource is almost always on the margin (e.g., see the line labeled AZNMNV in Figure 14). Moreover, because the assumed heat rates of gas-fired units lie within a relatively narrow range, even as the identity of the marginal, price-setting unit changes, prices do not change very much. Second, the simulations seem to produce far smaller inter-regional price differentials than have been observed historically, perhaps because of the manner in which losses are modeled or because of heat rate assumptions. Third, to the extent that the model produces price spikes outside of the narrow range in which the prices for the vast majority of hours fall, it is not transparent how the model arrives at these prices.

We do not have precise information about the resource and transmission assumptions used in the Gridview model data set. However, based on conversations with ABB, we strongly suspect that the primary reason that the model produces results that appear unrealistic by current standards is that it assumes a significantly different resource mix and substantial transmission additions relative to the resources and transmission that currently exist.

[58] See Smith and Winkler (2006). A similar argument appears in Hobbs and Hepenstal, (1989).

[59] Examples include the "winner's curse" phenomenon in auctions, where the highest bidder is the most optimistic and therefore sure to be wrong, and the survivorship bias in the estimation of mutual fund or hedge fund returns, where the failed firms are not counted in the averages.

6.5.1 Simulation results for Scenarios with Varying Gas Prices

ABB produced simulation results for three gas price scenarios: $5, 7, and 9/MMBtu. The gas price sensitivity cases demonstrate that gas is on the margin in many regions much more often than is the case in reality. In addition, the model seems to produce much less transmission congestion and much less geographically heterogeneous prices than are observed in reality. Undoubtedly, these results are driven by the fact that the simulations exclude outages. In addition, the simulations include gas-fired resources and transmission that do not currently exist.

ABB provided us with the identities of "marginal" units in each hour. They define units as marginal if they are operating at some level between consecutive heat rate blocks. In a competitive market, the variable costs of such marginal units should determine clearing prices. Of the approximately 30,000 marginal unit-hours in the $7/MMBtu gas simulation, the vast majority of them (>27,000) are gas. (Multiple units can be marginal in the same hour.)

As might be expected given the preponderance of gas-fired marginal units, average power prices more or less scale with gas prices. In Table 5, we show annual average power prices and "market heat rates" by geographic bubble for the $5/MMBtu, $7/MMBtu, and $9/MMBtu gas scenarios. Market heat rates effectively normalize the power prices for changes in gas prices. In a system in which gas is always marginal, market heat rates should not change as gas prices change. As shown in Table 5, the market heat rates do not vary much at each geographic bubble, looking across the three gas price scenarios.[60]

[60] To compute the market heat rates, we subtracted $2/MWh from the annual average power price for each bubble to account for variable O&M costs and divided by the gas price (e.g., $5/MMBtu, $7/MMBtu, and $9/MMBtu respectively)

Table 5. Average prices and market heat rates for gas price sensitivities

	Average price ($/MWh)			Market heat rates (MMBtu/MWh)		
Gas price	$5/MMBtu	$7/MMBtu	$9/MMBtu	$5/MMBtu	$7/MMBtu	$9/MMBtu
Area						
Alberta	34.12	46.85	58.95	6.4	6.4	6.3
Arizona	43.28	59.58	75.85	8.3	8.2	8.2
BC Hydro	38.41	53.98	69.47	7.3	7.4	7.5
BHB	35.38	50.54	65.51	6.7	6.9	7.1
Black Hills	35	49.78	64.33	6.6	6.8	6.9
Bonanza	34.95	48.3	61.53	6.6	6.6	6.6
Colorado (East)	36.69	50.81	64.55	6.9	7.0	7.0
Colorado (West)	36.65	50.67	64.15	6.9	7.0	6.9
Idaho	39.65	55.69	71.45	7.5	7.7	7.7
IID	46.45	62.86	79.24	8.9	8.7	8.6
IPP	44.98	61.2	77.27	8.6	8.5	8.4
Jim Bridger	38.3	53.72	69.21	7.3	7.4	7.5
KGB	38.76	54.73	70.35	7.4	7.5	7.6
LADWP	41.01	55.51	69.95	7.8	7.6	7.6
LRS	34.75	49.3	63.58	6.6	6.8	6.8
Mexico	45.91	61.53	77.65	8.8	8.5	8.4
Montana	33.86	49.82	65.46	6.4	6.8	7.1
NM	39.38	53.78	67.95	7.5	7.4	7.3
NV	44.16	59.72	75.25	8.4	8.2	8.1
Pacific Northwest (East)	40.26	56.14	71.8	7.7	7.7	7.8
Pacific Northwest (West)	40.77	56.86	72.74	7.8	7.8	7.9
PGE (Bay Area)	47.16	63.41	79.52	9.0	8.8	8.6
PGE (Central Valley)	47.08	63.3	79.4	9.0	8.8	8.6
SCE	45.98	62.12	78.2	8.8	8.6	8.5
SDGE	46.56	62.96	79.35	8.9	8.7	8.6
Sierra Pacific	44.43	60.4	76.17	8.5	8.3	8.2
Utah (North)	40.25	56.41	72.45	7.7	7.8	7.8
Utah (South)	40.22	56.28	72.21	7.6	7.8	7.8
WAPA	45.11	61.43	77.63	8.6	8.5	8.4
Wyoming	35.5	50.35	65.01	6.7	6.9	7.0
Wyoming (SW)	37.59	52.77	67.9	7.1	7.3	7.3
Yellow Tail	34.98	50.4	65.63	6.6	6.9	7.1

In addition to producing prices that are low and in a relatively narrow range corresponding roughly to the costs of different gas-fired technologies, the model produces prices with relatively little temporal and geographic dispersion. We illustrate this point in Table 6 which compares the monthly on-peak[61] market heat rates obtained from the production cost simulations for Arizona and Pacific Northwest/East bubbles at varying gas prices with the market heat rates derived from the raw day-ahead power and gas price data used in our econometric analysis.

[61] We use the standard definition of on-peak, i.e., hours ending 7-22 on Monday-Saturday.

Table 6. Observed and simulated on-peak market heat-rates

	Actual				GridView simulation results		
	2002	2003	2004	2005	$5/MMBtu	$7/MMBtu	$9/MMBtu
Month	Palo Verde				Arizona		
Jan	9.6	8.1	8.0	8.4	8.6	8.6	8.5
Feb	9.6	9.1	8.2	8.2	8.6	8.6	8.5
Mar	10.8	8.7	8.0	7.8	8.7	8.6	8.5
Apr	8.9	8.3	8.3	7.9	8.7	8.7	8.7
May	8.5	8.6	8.9	8.3	8.7	8.6	8.6
Jun	10.9	9.6	8.8	8.7	9.1	8.9	8.9
Jul	13.5	12.2	10.6	11.0	9.2	9.0	9.1
Aug	10.7	10.3	9.5	9.6	9.2	9.0	8.9
Sep	9.6	9.5	8.5	8.6	9.0	8.9	8.8
Oct	8.7	9.8	8.4	8.3	8.7	8.6	8.6
Nov	8.2	8.2	8.4	8.4	8.7	8.6	8.5
Dec	8.8	7.8	8.5	8.1	8.7	8.6	8.5
All	9.8	9.2	8.7	8.6	8.8	8.7	8.7
	Mid-Columbia				Pacific Northwest-East		
Jan	8.1	7.8	8.0	8.4	8.9	8.8	8.7
Feb	8.7	8.6	8.0	7.9	8.8	8.8	8.7
Mar	11.2	7.5	7.5	7.6	9.0	8.9	8.8
Apr	6.2	6.4	7.7	7.8	8.8	8.7	8.6
May	6.5	6.0	8.1	6.0	8.8	8.8	8.7
Jun	3.1	6.7	5.8	6.4	8.6	8.6	8.5
Jul	4.0	9.9	9.0	8.9	9.0	8.9	8.8
Aug	6.3	8.6	9.2	8.8	9.3	9.2	9.0
Sep	7.3	9.2	8.2	8.0	9.6	9.3	9.2
Oct	7.9	8.1	8.2	7.7	9.2	9.0	8.9
Nov	7.8	8.2	7.9	8.4	9.0	8.9	8.8
Dec	8.8	7.2	7.8	9.3	9.2	9.0	8.9
All	7.2	7.8	7.9	7.9	9.0	8.9	8.8

Figure 16 and Figure 17 provide graphical representations of these results for Palo Verde and Mid-Columbia respectively.

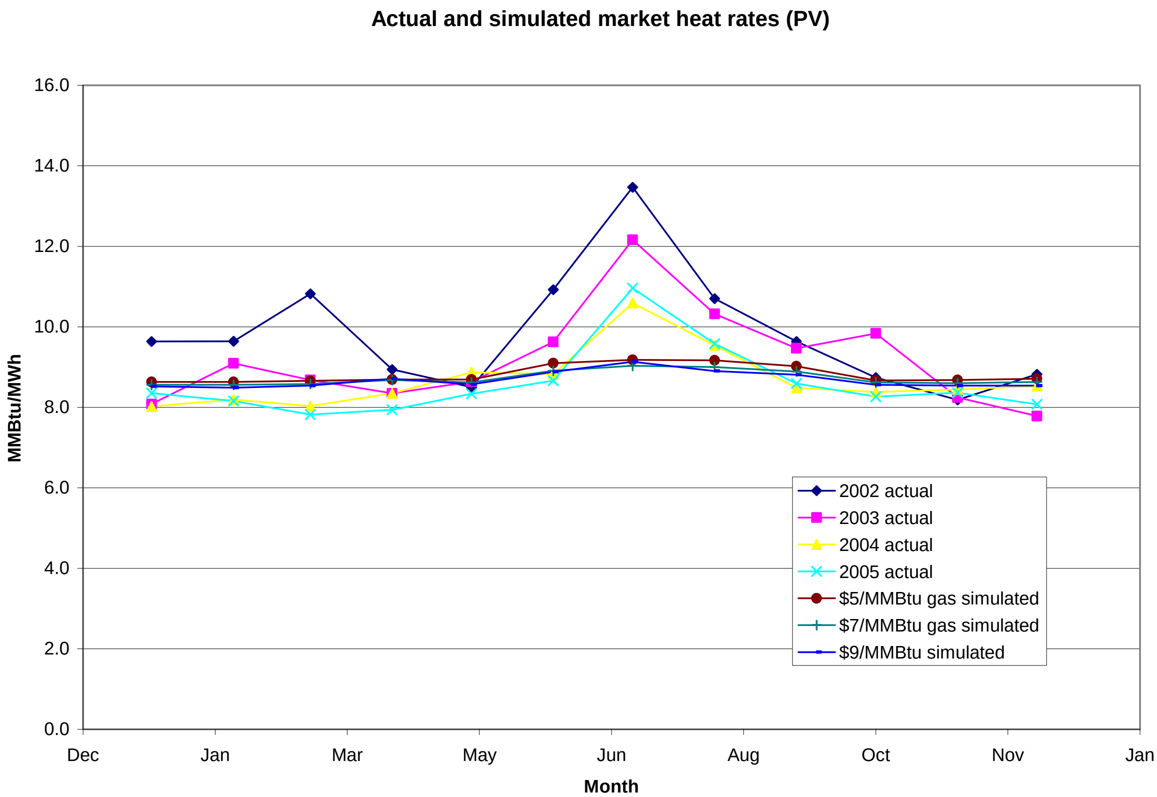

Figure 16. Observed and simulated on-peak market heat-rates (PV)

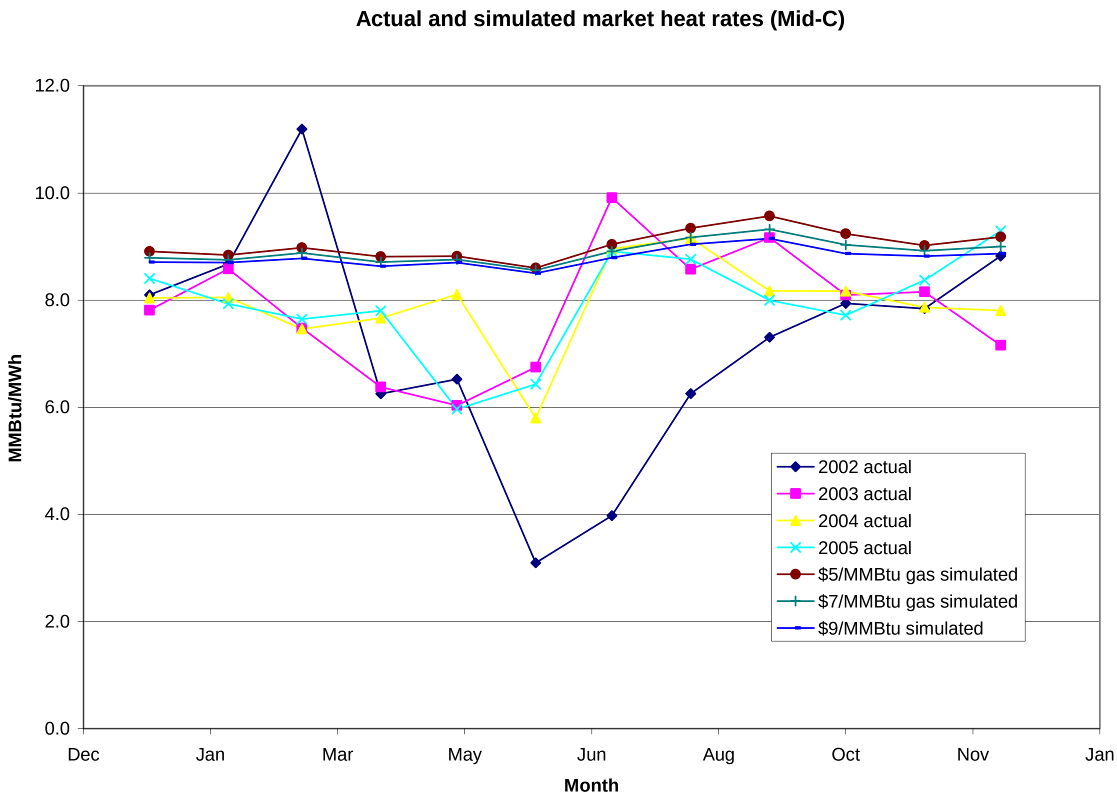

Figure 17. Observed and simulated on-peak market heat-rates (Mid-C)

Table 6, Figure 16, and Figure 17 highlight two aspects of the simulation results. First, the simulations do not reproduce observed seasonal fluctuations in market heat-rates. In particular, there is nothing like the dip in prices in the late spring, corresponding to the spring run-off, in the simulation results. In addition, the simulations do not capture observed increases in market heat-rates in the summer in the Southwest. Second, the simulations suggest that market heat-rates are higher on average in the Pacific Northwest than in the Southwest. For example, at $7/MMBtu gas, the annual average on-peak market heat rate for the Pacific Northwest-East bubble is 8.9 MMBtu/MWh compared to 8.7 MMBtu/MWh for Arizona. Again, this is inconsistent with recent history.

With respect to geographic price dispersion, congestion into and within California is a salient feature of Western wholesale power markets. We attempted to examine such congestion by tabulating the number of hours in which the paths between different bubbles appear to be congested based on price differentials between bubbles. We define the path between two bubbles as congested if the price difference exceeds $5/MWh.

Based on this criterion, we observed the following results.

- In the $7/MMBtu gas price scenario, there are no hours in the year in which there is congestion between the Pacific Northwest and Northern California. By comparison, the California ISO claims that there was congestion into Northern California from the

Northwest in approximately 13% of *all* hours and that the average price differential between the regions in those hours was $9/MWh.[62]

- Similarly, the simulation finds only 17 hours in the year, in which there is congestion into Southern California from Arizona. By comparison, according to the CAISO, the Palo Verde branch group, one of the major interfaces linking Southern California and Arizona was congested in the import direction in 8% of all hours (i.e. 700 hours).[63]
- In contrast, the simulation seems to overstate congestion *within* California. There are 334 hours of north to south congestion within California in the simulation (~4% of the hours in the year). By comparison, the ISO reports that Path 26, linking northern and southern California, was congested in the north to south direction in only 1% of all hours in 2005. Perhaps the simulation does not reflect relatively recent transmission upgrades within California. Alternatively, the CAISO only manages certain parts of the lines entering California, in particular, not those controlled by municipal utilities. It is possible for the CAISO portion to be congested when the other portion is not. It is unclear whether GridView is modeling such arrangements.

6.5.2 Simulation Results for Cases that Include Unit Outages

The simulations that include outages should provide a marginally more realistic characterization of price formation in the West. Because we have information from these simulations similar to the data that we included in our econometric models, we can estimate similar econometric models on the results of the simulations to see whether we get parameter estimates that are remotely similar.

In Table 7, we report results of one regression based on the results for the Arizona bubble. The data are hourly and we stack the results of the four outage cases so that there are 35,136 observations (i.e., four times 8,784 observations). We report the parameter estimates for a few variables of interest. The regressions include the full set of month, day-of-week dummy variables that our econometric model regressions included, which were based on observed market data. In addition, because they are based on hourly data, they also include hour-of-day dummies.

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[62] See Table 5.3 of CAISO (2006). Note that we are summarizing results for the COI branch group. The ISO managed congestion on this interface for only eleven of the twelve months in 2005. Beginning December 1, 2005, the branch group was split into two parts: one that goes from Oregon to the CAISO control area and another that goes from Oregon to the SMUD control area.

[63] *Ibid.*

Table 7. Results from regression based on simulation results

	log(AZ price)
log(AZ load)	0.084
	(58.35)**
log(California load)	0.074
	(33.76)**
Southwest nuclear outages (MW)	0.000005
	(17.32)**
Southwest coal outages (MW)	0.000006
	(19.38)**
California nuclear outages (MW)	0.000001
	(5.07)**
Observations	35,136
R-squared	0.86
Absolute value of t statistics in parentheses	
* significant at 5%; ** significant at 1%	

The coefficients on load are approximately 90% smaller than the coefficients that we estimated from real data. Similarly, the coefficients on the amount of baseload nuclear and coal capacity that is forced out are approximately four times smaller than the coefficients on nuclear outages that we estimated from real data. This just confirms the claims above that the simulations produce very "flat" prices in the sense that supply and demand shocks have very attenuated effects on prices.

To the extent that the simulations produce occasional price spikes, it is difficult to develop much intuition for why they occur. Consider the following example: in the second outage case, for hour ending 17 on June 25, the price in Arizona is ~$193/MWh. A combustion turbine is deemed marginal in Arizona, but the clearing price is far in excess of its costs. The prices produced by the simulation for this specific hour on this day exhibit significant geographic dispersion ranging from the mid-20s east of the Rockies, to around 70 in Northern California, to the 80s and 90s in Southern California, to the 40s in the Pacific Northwest. Nevertheless, the simulation results indicate that only three units are marginal in the West in the hour so that even relatively large price differentials within zones consisting of many bubbles are due to losses. Can losses alone plausibly explain a $20 differential between Northern and Southern California? Other hours with high prices in specific bubbles exhibit similar anomalies.

6.6 Final Observations Regarding Production Cost Modeling for Market Monitoring Purposes

The foregoing analysis reflects our attempts to gain additional insight into price formation in the West based on the results of several simulations of the Western power market. We found the exercise to be challenging for the reasons described above. None of this is to suggest that there is anything wrong with the simulations *per se* or that they are internally inconsistent or that they might not be useful for other purposes besides market monitoring. Instead, it suggests that they reflect load, resource, and other assumptions that are sufficiently far-removed from reality as to be rendered not useful to understand price formation and hence not useful for market monitoring purposes in the near future. Alternatively, the simulations may do a good job of capturing the physical reality of the Western power market, but recent prices may reflect other factors, potentially including the exercise of market power. This is a potential challenge associated with the econometric approach to market monitoring that we have described above. As discussed previously, to identify prices as abnormal, it is necessary to take a stand on what constitutes normal prices. In the absence of any significant claims of market abuse in the last few years, we would argue that observed prices are normal by some measure and hence can be used to establish preliminary competitive benchmarks for identifying abnormal prices that may warrant further analysis.

7. The Role of Company-specific Market Monitors and Independent Evaluators in the West

The preceding sections focused on the types of market monitoring that a West-wide market monitor might perform. In this section we briefly review the role of existing independent evaluators (IEs) and company-specific market monitors (MMs) in the West. The roles of these existing market monitors are relatively limited. On the other hand, they have access to data that a West-wide market monitor might not have.

7.1 Definition of Independent Evaluators/company-specific Market Monitors

In situations where there is potential for competitive problems, FERC and state commissions have opted for the use of company-specific market monitors or independent evaluators to oversee the behavior of regulated utilities. IE's typically monitor long-term procurement by utilities when there is the potential for the utility to favor an affiliate's proposal. MMs review utilities' behavior in short-term wholesale power and transmission markets where there is the potential for a utility to exercise local market power in wholesale power markets or to operate its transmission and generation assets in a manner that effectively denies access to non-utility generators. Despite the difference in focus, there is some commonality in the IE and MM functions.[64]

7.2 Affiliate Abuse is the Dominant Concern

The dominant concern addressed by IEs and company-specific MMs is that regulated vertically integrated utilities might abuse their monopoly transmission assets or their monopsonistic position as a buyer of power or their affiliation with owners of generation. Dedicated IEs and MMs are necessary because of the complex technical issues involved in either short-run power system operation or the economic evaluation of new resources through long-term procurements.

A principal purpose of the IE or MM is to assure "fairness" in the utility's evaluation of power-supply offers or requests for transmission service by third parties. In the context of electricity markets, given their complexity, assuring fairness requires some independent assessment that relevant economic factors, business issues, and engineering constraints are being applied appropriately and accurately. That is, there needs to be some independent norm of proper or efficient behavior against which to determine a "fair" outcome – one that is consistent with reaching "just and reasonable" rates when the utility is purchasing power, and one that is non-discriminatory when it is providing access to monopoly transmission resources.

Fairness cannot be assessed without some concern for efficiency and appropriateness. One can always toss dice to determine who gets transmission access or power procurement contracts. Such a process is "fair" because no one is being discriminated against. Tossing dice, however, is not an efficient or appropriate way to allocate transmission or procure new resources.

[64] The FERC Order in the OG&E/NRG McClain case (108 FERC ¶ 61,004, July 2, 2004) discusses an interesting mix of long-term procurement and short-term wholesale market issues. In this case FERC decided that the acquisition by a regulated utility of an independent power project raised competitive issues that were best addressed by retaining an MM until OG&E joined a functioning RTO.

The extent to which an IE or MM can determine efficiency and appropriateness is a question we addressed by looking at several specific examples. We review the First Quarter 2006 MM report for Public Service of New Mexico (PNM) and the testimony provided by Pacific Gas and Electric Company (PG&E)'s IE (Sedway Consulting) regarding new resource procurement.

7.3 Potomac Economics PNM Report

As a condition of the PNM merger with Texas-New Mexico Power Company, FERC approved a PNM proposal that it employ a MM who would issue quarterly reports.[65] The MM, Potomac Economics, is charged with detecting any anticompetitive conduct in which PNM may engage from operating its transmission system, including the effect of PNM generation dispatch on the transmission system. We review the public version of the Potomac Economics (PE) report that covers the First Quarter of 2006 (PE Report, May 2006). It is our understanding that all MM reports follow the same format.[66] This discussion will illustrate the use of both public and confidential information by the MM, the comparatively imprecise standards for evaluating behavior, and the narrow geographic scope of analysis.

The PE report first "evaluates" wholesale power prices in the PNM market area after-the-fact by comparing the Platt's Four Corners (FC) daily bilateral contract price with "the daily cost of natural gas in the region."[67] The gas cost is converted to a power price at 8,000 Btu/kWh and plotted in Figure 1 of the report along with the Four Corners price and the PNM peak load. The figure shows a close relationship between gas and power costs; PE says the correlation is 94%. Figure 2 shows the gas/power relationship by month (January, February and March) from 2003-2006. This figure shows that "electricity prices have generally moved with natural gas prices over time." This analysis, which appears to be based on public data, is a bit informal compared to the econometric models described in Section 5 of this study or the market heat rate calculations in Table 6 above. PE does not examine the connection between FC prices and those at the larger regional trading hub at Palo Verde. If PNM did, in fact, manipulate the FC price, how would the MM know?

The bulk of the report focuses on confidential PNM data. PNM's purchase and sale data is summarized briefly in Figure 3, which is redacted in the public version. These data show that on average PNM was a net buyer, and therefore did not have an incentive to exercise market power to raise wholesale prices. In a subsequent section, PE examines the relationship between PNM transaction prices and transmission congestion. Before making this assessment, PE presents some data analyzing PNM transmission system performance more generally. Figures 4 and 5

[65] See 110 FERC 61,204, March 2, 2005.

[66] FERC first approved a company-specific MM as an interim measure for American Electric Power (AEP) system in conjunction with requiring AEP to join an RTO (91 FERC ¶ 61,208, 2000). The PNM market monitoring plan is modeled on one approved in connection a FERC decision involving Unisource's acquisition of transmission assets (see 109 FERC ¶ 61,047, 2004). See 110 FERC ¶ 61,204, 2005 for the PNM order.

[67] It is not completely clear from the text whether the FC price is for peak deliveries or exactly what the gas delivery location is.

show that PNM is making the full capability of the critical Four Corners West Mesa path available for use (p. 13). Figures 6, 7, and 8 summarizes data on requests for transmission access. PE finds no evidence that PNM acted to restrict access (p. 15). Figure 9, which is redacted in the public version, presents daily data on PNM sales prices and days when short term transmission requests were denied. PE finds "no significant difference between sales prices on days with refusals versus all other days" (p. 17).

Next PE examines whether PNM may have denied transmission access due to uneconomic dispatch of its own generation. Doing this requires some notion of economic dispatch. PE constructs a supply stack model.[68] PE recognizes that its model neglects the kinds of internal system operating constraints capable of being represented in production cost models, but concludes that the costs of that approach would exceed its benefits (p. 20). The supply stack is adjusted for PNM-reported outages. Using the supply-stack approach, PE calculates the amount of out-of-merit generation by day and plots it along with path flow levels and days with transmission service denials in Figure 11. PE finds "no evidence that out-of-merit dispatch events limited access" (p.21).

The PE analysis covers a period of time when there do not appear to have been any shocks to the regional power system, such as major facility outages or unusually high loads. It is unclear, however, how PE's methods would identify any such shocks or determine whether the response to them was "normal" or not. For example, it is not apparent whether the MM's approach would enable it to determine whether PNM had the ability to influence the FC bilateral price. If the market were "dysfunctional" in some broad sense, how could the MM tell? If there were abnormal relationships between FC prices and those at Palo Verde, would the MM's approach pick them up? If a regional shock induced PNM to behave in an anti-competitive manner by denying transmission access, presumably PE would be able to detect this and report on it. Given the narrow mandate for the MM, it is not clear if these broader questions of market performance are necessarily within their scope of responsibility. The existence of the MM, however, may be sufficient in itself to discipline behavior at least in the PNM market area, if not in the wider region.

7.4 Sedway Consulting Testimony and Report on PG&E RFO

The California Public Utilities Commission has mandated the use of an Independent Evaluator (IE) in resource procurements undertaken by regulated electric utilities when an affiliate of the utility may participate or has an active proposal under consideration by the utility (CPUC, 2004). A substantial concern in utility procurements of generation is that the buyer's economic and financial interests can skew the evaluation process. This might occur if there were offers by utility affiliates, or if the utility were to become an owner of the facilities offered. PG&E retained Sedway Consulting (Sedway) for PGE's 2004 Long Term Request for Offers (RFO). Sedway filed testimony and a report documenting its work as the IE for this process. We review these documents briefly, emphasizing the extent to which Sedway carried out independent market assessment activities (as opposed to focusing on Sedway's review of PGE's procurement processes themselves).

[68] Figure 10, which is redacted in the public version, is the PE supply stack.

In the PG&E RFO there were no affiliate bids.[69] Nonetheless, there were offers that resulted in utility ownership. In some cases, these were projects that could have been sold to PG&E or where the output could have been purchased from a third party under a long term contract. Ultimately the ownership option was selected rather than the contract option (Taylor, 2006b, pp.24-30). The IE specifically supported the lack of bias in the process that ultimately led to the regulatory approval of the selection of the ownership option (Taylor, 2006a, pp.28-9).

The majority of the effort documented in the Sedway's report was process-oriented: monitoring of communications, confirmation of calculations, review of negotiations, assessment of non-price factors qualitatively.[70] A few issues regarding methods and data in the PG&E case are worth a brief discussion.

PG&E used a spread option model to estimate benefits of the bids. Spread options are a particular kind of option for which the payoff is related to the difference between the prices of two different products. These were first used as a strictly financial instrument in commodity markets other than electricity.[71] They have subsequently been introduced into electricity trading, and then into the valuation of electricity contracts and projects, where the spread is typically between power and gas prices.[72] Sedway observes that the use of this approach by PG&E is unique for long-term resource evaluation. Spread option methods are usually used for short-term trading (Taylor, 2006b, p.8). Even so, it may be appropriate to use such models in resource planning. Peaking projects, for example, may be under-valued without the use of option methods, because so much of their benefit comes from being able to hedge against infrequent price spikes. This "option value" is frequently underestimated or ignored by more traditional valuation methods. As part of its evaluation, Sedway uses its own model, which it "calibrates" to the PG&E model. It is unclear whether this calibration represents an independent replication of the results in the PG&E model or not. The brief example illustrating the process seems more like linear interpolation than independent replication of the underlying algorithm (Taylor, 2006b, Appendix B).

To summarize, the independent evaluator's activities in this case are more of an audit function than an independent assessment of value. Sedway does not provide its own assessment of such key drivers of value as future gas prices. Some commentators on the IE process have suggested that such forecasts be done by the IE.[73] However, there are disagreements about whether the IE

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[69] The IE documents do not say explicitly that there were no affiliate bids, but the issue is never discussed. PG&E had an unregulated affiliate that filed for bankruptcy and whose asserts were turned over to lenders.

[70] In this way, Sedway's role was similar to the role of the independent monitor overseeing recent procurements by the Arizona investor-owned utilities. The standards applied to those procurements by the ACC were fairness and consistency. The independent monitor report is available on the Arizona Corporation Commission website (Accion Group, 2003).

[71] W. Margrabe, (1978) and D. Shimko, (1994).

[72] See Deng, S. J., B. Johnson, and A. Sogomonian, (2001).

[73] *Electric Power Supply Association* (2004).

function should go that far. The more limited interpretation of the IE role as an audit function still leaves open the question of whether algorithm replication is the audit standard or not. With complex production cost or spread option methods, there is opportunity for manipulation of calculations.[74] Independent replication of algorithms would address the manipulation concern. In this case, it is unclear exactly what the Sedway model does, but the limited discussion suggests the evaluation does not attempt algorithm replication.

7.5 Regional and State Linkages

At present, the activities of IE and MM in the West do not involve regional assessments. This is more of an issue for the MM than the IE. While the economic evaluations overseen by IEs clearly examine interactions between the activities of an entity within a state and the broader regional market, it is not clear that failing to assess the state/region linkage really limits the IE in any important way. It is less clear that a company-specific MM can be maximally effective absent a more explicit regional view or focus on behaviors within the region. This is not to say that MM activities are not useful, only that they are limited and may miss effects that are otherwise important to uncovering dysfunctionalities in a regional power market.

[74] This issue is discussed in a FERC case involving affiliate transactions resulting from a solicitation for contracts (FERC, 2005b at ¶ 42-51).

8. Conclusions

This study has examined the feasibility of West-wide market monitoring given readily available data. Because the West outside of California and Alberta does not have RTOs that perform centralized unit commitment and dispatch, the rich data that are typically available to market monitors in RTO markets are not available in much of the West.[75] We develop simple econometric models of wholesale power prices in the West that might be used for market monitoring. We also examine whether production cost simulations that have been developed for long-run planning might be useful for market monitoring. We find that simple econometric models go a long ways towards explaining wholesale power prices in the West and might be used to identify potentially anomalous prices. In contrast, we find that the simulated prices from a specific set of production cost simulations exhibit characteristics that are sufficiently different from observed prices that we question their usefulness for explaining price formation in the West and hence their usefulness as a market monitoring tool.

If a monitoring function based on the kind of econometric modeling illustrated here is thought to be a desirable, albeit second-best, alternative, then there are institutional questions that need to be addressed. What is the preferred institutional arrangement for such a function? How might it be supported both financially and intellectually? These questions are outside the scope of the present effort, but are a logical next step for market participants, stakeholders and policymakers interested in West-wide market monitoring.

[75] While we fully acknowledge the wide range of views about the costs and benefits of RTO, one undisputed benefit is that RTO tend to produce voluminous amounts of detailed operational and price data for market monitoring.

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Appendix A. GridView Simulations

A.1 Introduction

Lawrence Berkeley National Laboratory and The Analysis Group conducted a study for the Western Interstate Energy Board Committee on Regional Power Cooperation (CREPC) that draws upon the SSG-WI 2008 reference case data. ABB assisted the Analysis Group to deliver the following results:

- For each hour of year 2008 simulation, report on the marginal thermal generators in each of the 33 (or so) zones of the SSG-WI simulation topology. The definition of a marginal thermal unit is one that is operating at some level above its minimum operating output level and below its maximum output level. The reported results include fuel type, variable cost (variable fuel, O&M and emissions cost if applicable), and zone.
- There were three SSG-WI simulations of calendar year 2008 based on three different assumptions about gas prices: low ($5/MMBtu), medium ($7/MMBtu) and high ($9/MMBtu).

ABB's GridView Market Simulation Software was used for this analysis. The core of GridView is a transmission constrained unit commitment and economic dispatch algorithm as shown in Figure A-1. GridView mimics the operation of an electric market by dispatching units based on their bid prices while taking into account the flow limits on transmission lines and interfaces under normal, as well as under contingency conditions. The outputs from a GridView simulation include information such as hourly unit dispatch, locational marginal prices (LMP) at buses, flow on lines, and congestion cost of limiting lines.

In this analysis, units in the WECC system were assumed to bid their variable costs in the energy market, which was calculated by adding the fuel, and variable operation and maintenance costs. This is a valid assumption during most hours except when the market has a tight reserve margin or when certain units exercise market power.

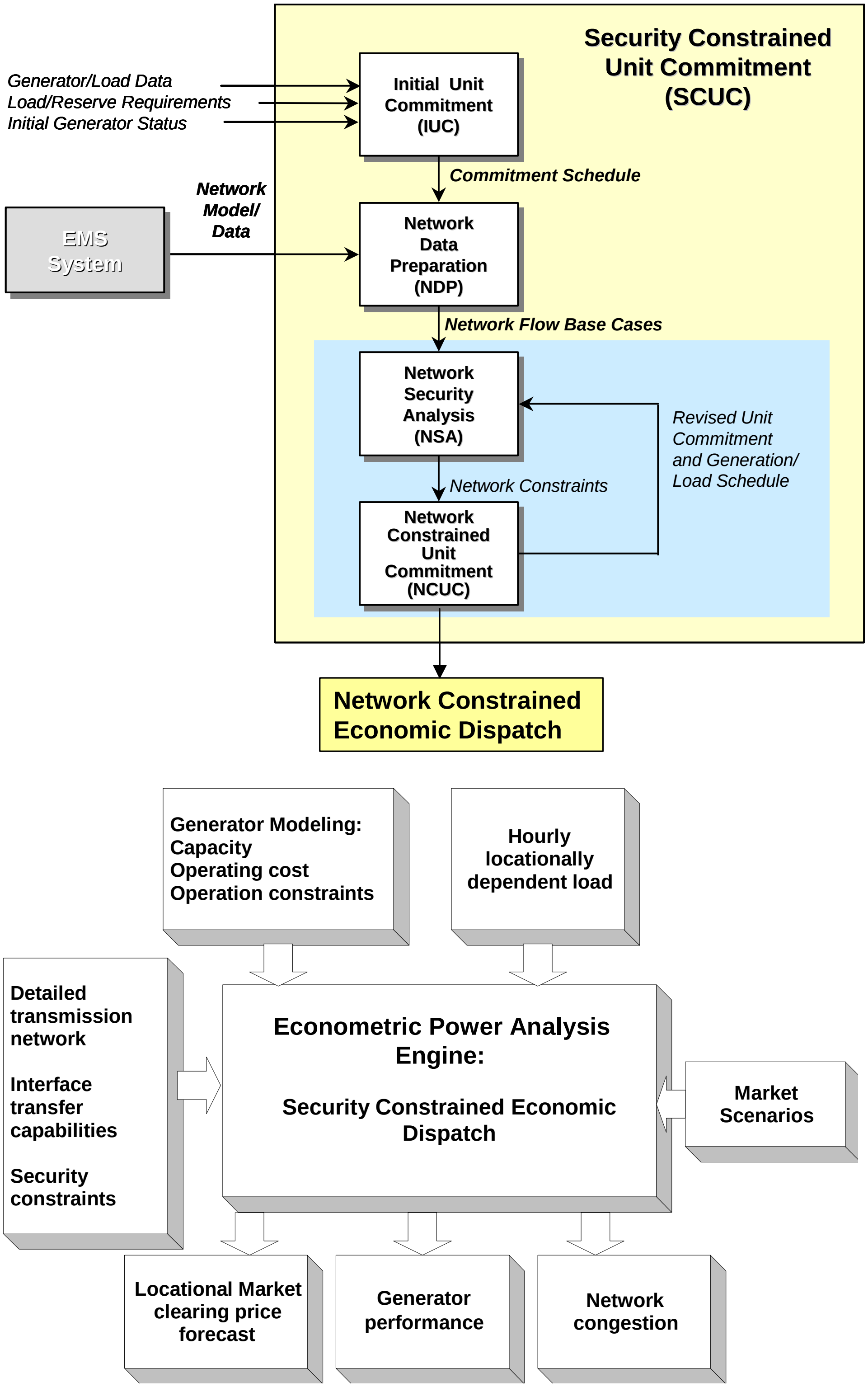

Figure A-1 GridView's simplified block diagram

A.2 Data and Assumptions

In this section, ABB summarizes key input data and assumptions used in this study. The SSG-WI 2008 reference database was used to create three scenarios with different fuel price options: low ($5/MMBtu), medium ($7/MMBtu) and high ($9/MMBtu).

A.2.1 Load and Capacity Assumptions

The geographical location of load in the transmission system is given by the bus to which the load is connected. Groups of load buses (a bus having at least one load connected to it) are organized into bubble areas. An annual load profile in EEI format is assigned to each bubble area to describe the hourly load variation during the entire year. Those area load profiles were created based on 2008 SSG-WI load forecast data. GridView assigns the area's load shape to each bus within that area using the ratio of that bus' load to the region load. The maintenance algorithm in GridView was used to create the maintenance schedule for all units. The available capacity for each region is calculated from the installed capacity and the capacity that is on maintenance.

A.2.2 Transmission System Assumptions

In the SSG-WI database, all transmission lines with voltage level equal to or greater than 345-kV were monitored (the thermal limits were enforced during economic dispatch). All interfaces and critical nomograms in WECC path rating catalog were modeled and monitored.

A.2.3 Calculation Assumptions

The transmission security constrained unit commitment (SCUC) and economic dispatch (SCED) used in the simulation requires generation cost data (e.g., incremental heat rate or bid prices) and MW limitations on individual circuits, transmission interfaces and individual generating units to calculate:

- The minimum cost of generation dispatch that satisfies the nomograms and transmission constraints;
- Locational Marginal Price (LMP) for each bus in the system;
- Committed capacity to meet the reliability needs (RMR units);
- Constraints affecting economic operation, affecting price levels or causing transmission bottlenecks that level the prices in different price zones.

SCUC and SCED for the market minimize all incurred costs while serving the load subject to network constraints and ensure operating reliability. It has been well established[76] that economic dispatch models mimic the behavior of a competitive market for wholesale power such as the WECC market and reveal the varying clearing prices for power throughout the system. It was sensible to use this model to investigate the expected operation of the generators participating in the WECC markets and the resulting production cost variations and congestion situations in the transmission system.

[76] See Schweppe. Caramanis, Tabors and Bohn, (1988).

Marginal losses were included in the calculation with distributed reference buses.

Wheeling Charges representing transmission access charge tariff between different ISO controlled regions were included in the simulation. The average wheeling rate was $2.8/MWh.

The transmission constraints can be branch thermal ratings, operating nomograms, or voltage and stability in the form of interface limits under normal and contingency conditions. The nomograms in GridView are mathematically expressed as an inequality, where the left hand side of the inequality is a linear combination of power flows on relevant transmission interfaces, generator output, and/or area loads.

To reflect the day-ahead bidding settlement in the market, only inter-zonal transmission constraints, which were modeled as interfaces and nomograms, were enforced during security constrained unit commitment (SCUC) optimization loop. During security constrained economic dispatch (SCED), both inter-zonal and intra-zonal transmission constraints, which were represented by individual branch thermal limits, were enforced.